Section 4.

Projections of Demand

by

Tabors Caramanis & Associates

April, 1996

4. Demand

In this section we present various peak load and annual energy forecasts for the NEPOOL control area.[1] These data, except where noted, are from NEPOOL's own forecast, and include adjustments for DSM and cogeneration. Included for comparison are current capacity levels. We have also attempted to gauge the impact of price decreases on demand.

4.1 Peak Load Growth

Figures 4.1 and 4.2 show forecasts of summer and winter peak load for the NEPOOL control area. (NEPOOL, 1995, p. 1). The load scenarios included are as follows:

Reference. This is the adjusted reference load as forecasted by NEPOOL, representing load levels with a 50% chance of being exceeded The loads have been adjusted to reflect the impact of demand side management (DSM) programs[2] and cogeneration.[3] In this scenario, summer peak loads increase 11% over the next 10 years, from 20,400 to 22,700 MW, and winter peak loads increase 14%, from 19,400 to 22,100 MW.

High. This is NEPOOL's high load scenario, reflecting load levels with a 10% chance of being exceeded. The loads have been adjusted using the same DSM and cogeneration estimates used to adjust the reference load. In this scenario, summer peak loads increase 21% over the next 10 years, from 21,000 to 25,400 MW, and winter peak loads increase 22%, from 20,800 to 25,300 MW.

Low. This is NEPOOL's low load scenario, reflecting load levels with a 90% chance of being exceeded. The loads have been adjusted using the same DSM and cogeneration estimates used to adjust the reference load. In this scenario, summer peak loads increase 3% over the next 10 years, from 19,900 to 20,400 MW, and winter peak loads increase 7%, from 18,300 to 19,500 MW.

Price Response. This is a load scenario created by scaling the Reference scenario up to account for demand growth in response to an assumed price decrease of 25%.[4] Given a price elasticity of -0.1 (Hartman, 1978), demand would increase by 2.5% over the reference case. It is assumed that the price decreases and response would not be seen until 1998. In this scenario, summer peak loads increase 14% over the next 10 years, from 20,400 to 23,300 MW, and winter peak loads increase 17%, from 19,400 to 22,100 MW.

The capacity levels shown reflect the current supply position adjusted for known retirements and additions.[5] In this study, no attempt has been made to forecast increases in supply in response to

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[1] The NEPOOL control area differs only slightly from New England as a whole in that several small New England entities are not NEPOOL members and are not under NEPOOL control. Capacity and forecast loads for New England are within 1% of those for NEPOOL, for which data are more readily available.

[2] DSM impacts are company estimates of current and future non-OP4 interruptible contracts, peak load management, and conservation on peak, as reported to NEPOOL. There is only a single set of estimated impacts (rather than a range of scenarios), which ranges in magnitude from 5% to 11% of the unadjusted reference load between 1995 and 2005.

[3] Cogeneration is, in NEPOOL's terms, "non-utility generation netted from load and not claimed for capability," and is largely generation within customers' facilities. It is approximately 1% of the magnitude of the unadjusted reference load.

[4] Adjustments for DSM and cogeneration were applied after scaling the unadjusted reference load, in a manner consistent with that used for the High and Low scenarios.

[5] Included in system capacity are those utility and non-utility supply projects that are existing, under construction, or have received regulatory approval (but not those that

increasing loads. Summer and winter capacity levels remain relatively steady, averaging 25,200 MW (August) and 26,300 MW (January).[6]

As Figures 4.1 and 4.2 show, only the summer high growth scenario exceeds the system's planned capacity within the 10 year time frame of this study, in 2005. Even the Price Response scenario loads are still 6%-11% below currently planned capacity by 2005. The load for this scenario, reflecting the relative impact of price decreases, falls somewhere between NEPOOL's reference and high growth loads. Although all of the alternate scenarios diverge from the Reference scenario, none differ from it by more than 14% by 2005.

4.1 Energy Growth

Figure 4.3 shows NEPOOL's forecasted annual energy growth (NEPOOL, 1995, p.10), along with a Price Response scenario computed in the same manner as that for peak load. The NEPOOL forecast shows annual energy use increasing 15% by the year 2005 (from 113 to 130 TWh); accounting for growth due to price decreases results in a 20% increase in annual consumption over the same period (from 113 to 135 TWh).

References

Hartman, R. S., 1978. "Frontiers in Energy Demand Modeling," *Annual Review of Energy*, v. 4, 1976.

NEPOOL, 1995. *NEPOOL Forecast of Capacity, Energy, Loads and Transmission - 1995-2010*, April 1, 1995.

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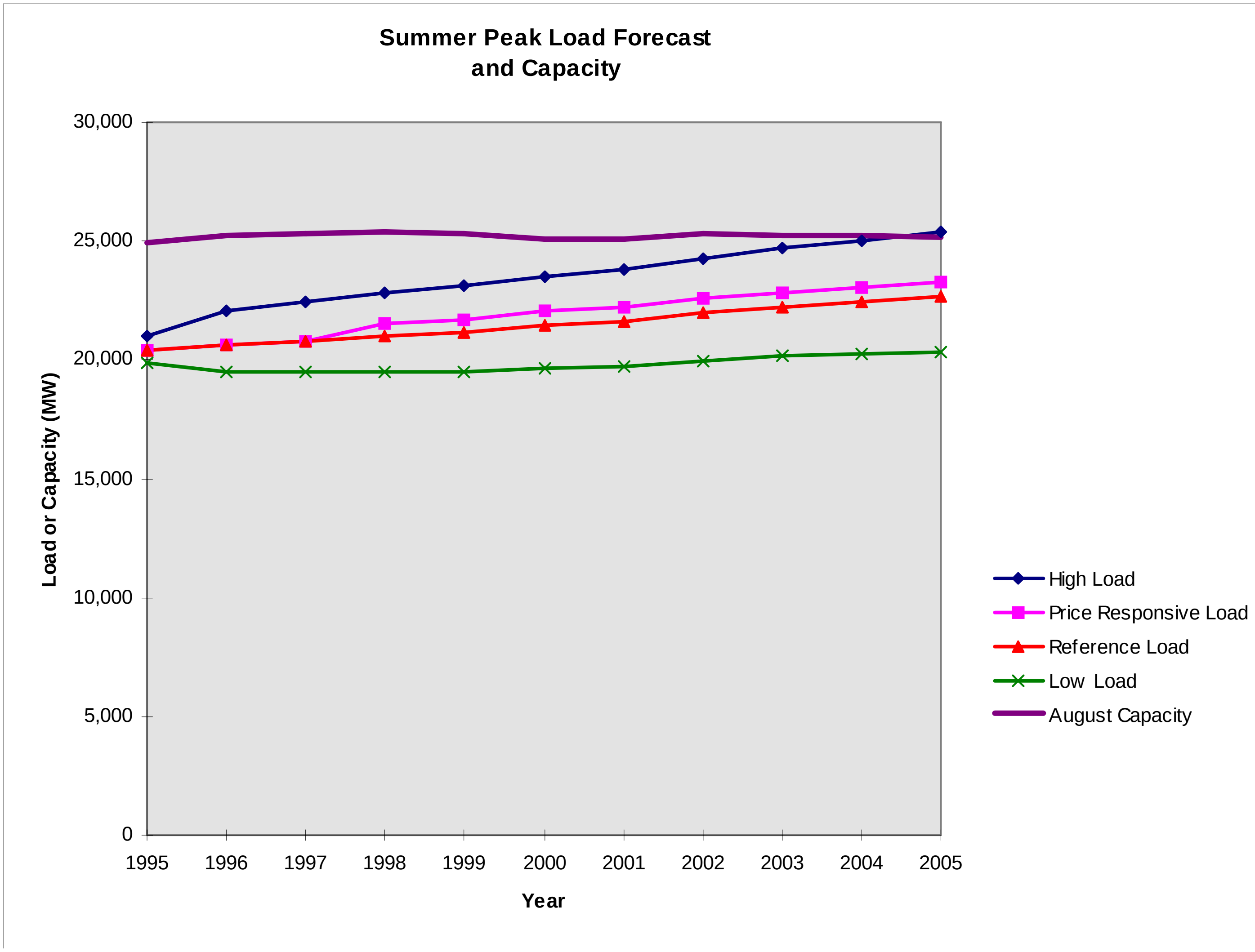
have only begun the licensing/permitting process or are proposed) and the net of firm purchases and sales. Deductions include planned deactivations, retirements, and reratings. Cogeneration is not included in system capacity, but is netted from load.

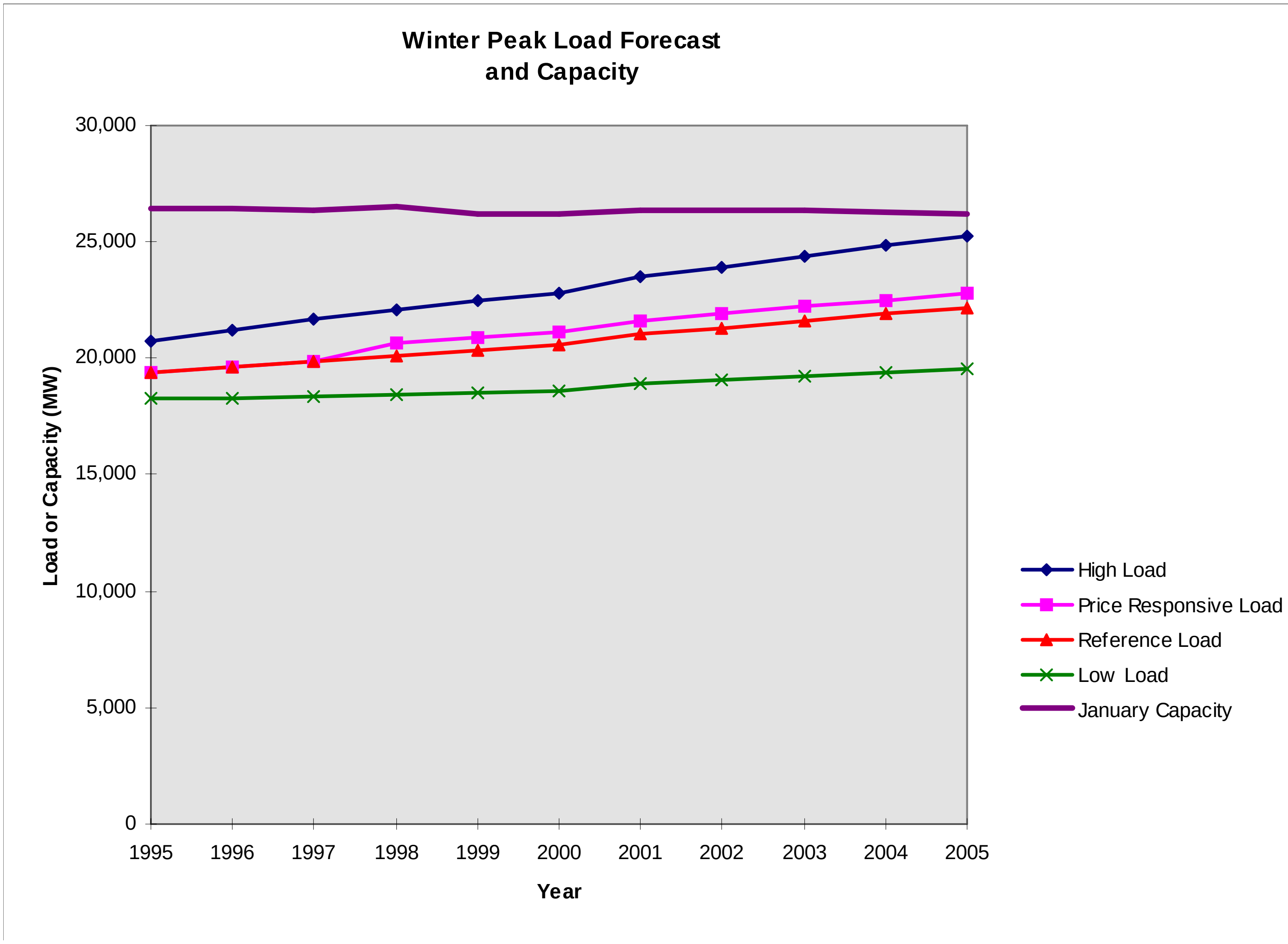
[6] Winter capacity exceeds summer capacity primarily due to temperature-related derating of thermal plants.

Figure 4.1


Summer Peak Load Forecast
and Capacity
30,000
25,000
20,000
15,000
10,000
5,000
0
Load or Capacity (MW)
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Year
High Load
Price Responsive Load
Reference Load
Low Load
August Capacity

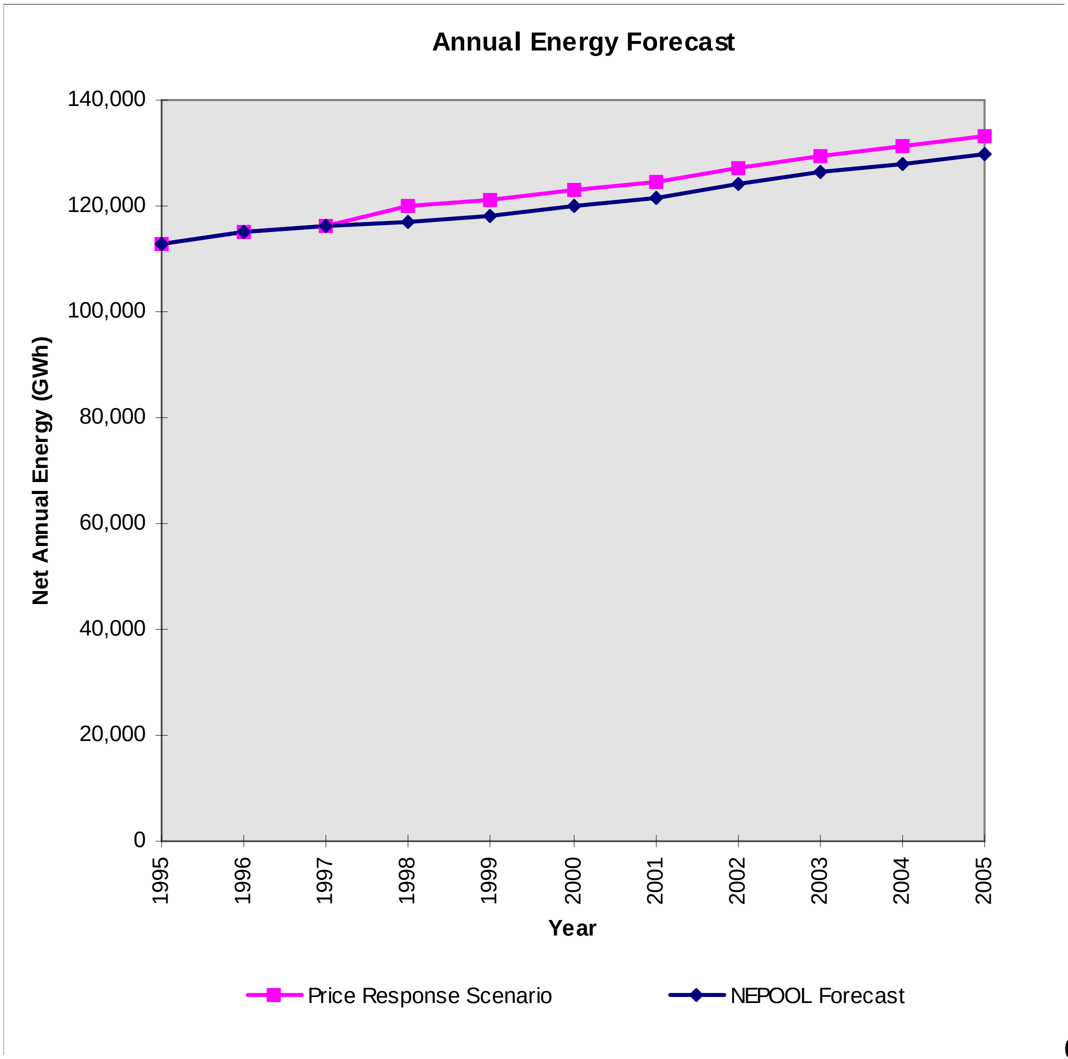
0

Figure 4.2


Winter Peak Load Forecast
and Capacity
30,000
25,000
20,000
15,000
10,000
5,000
0
Load or Capacity (MW)
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Year
High Load
Price Responsive Load
Reference Load
Low Load
January Capacity

0

Figure 4.3


Annual Energy Forecast
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Net Annual Energy (GWh)
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Year
Price Response Scenario
NEPOOL Forecast

0

Appendix A

REVIEW OF ALTERNATIVE OPERATING ARRANGEMENTS

by

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and

RICHARD D. TABORS

April, 1996

1. Models for Design and Operation of the New England Regional Electricity Supply Market

A. Introduction and Overview

This appendix presents an overview of the institutional arrangements for organization and operation of the New England electricity supply industry. There are a plethora of descriptions of alternative structures that have appeared from a range of sources. The structures are, however, outgrowths of two principal concepts. The first is a highly structured, mandatory pool, the second the open, bilateral contract market. The discussion below presents first the current structure in summary format and then presents a snapshot of a highly stylized pool and then bilateral system.

Regardless of the model chosen, there is a set of operational requirements that must be fulfilled for the "lights to stay on." These include frequency and voltage support, operation of the transmission grid and guarantee of both reliability and stability of the system as a whole. While there has been considerable discussion of the manner in which these services may be supplied, current discussions are centered on the establishment of an Independent System Operator (ISO) to provide some or all of these services. While we acknowledge that the ISO and its function are in the eyes of the beholder, we will use the term relatively generically as we describe the alternative market models in the first sections of this appendix. The middle section of this appendix then focuses on the function of an entity, the ISO, and provides our preferred model for its organization and operation. The final section looks at the question of transmission system ownership and control and provides a description of two models which we believe are functional for New England.

B. The Current Supply Industry Structure

The New England electric supply industry currently operates as a highly integrated pool. Virtually all generating units in the region are subject to central dispatch which is coordinated from the NEPOOL headquarters in Holyoke, Mass. through three regional control centers in each of Connecticut, Massachusetts and Maine. The current arrangements are the result of the 1965 Northeast blackout and a desire from the NE utilities to gain operating efficiencies through closer coordination.

Today the NE utilities plan and operate cooperatively through a committee structure that has provided for a relatively small central staff with responsibilities shared through the individual members. All operating rules are covered through the NEPOOL agreement and its amendments. NEPOOL is organized such that the joint operation of all utility assets is more efficient than the operation of the isolated utilities. The savings that are the documented difference between the utilities acting individually (referred to as own load) and their joint action are used to fund the operation of NEPOOL (including NEPEX – operations, and NEPLAN -- planning). The remainder of these are then divided between the member companies as a function of a formula that relates individual member's relative contribution to, and use of, the electrical resources of the total New England region. The rules of NEPOOL have been amended 31 times. Proposed changes to the rules are subject to significant negotiation within the NEPOOL membership, the effect of which may impact the timeline for restructuring.

In the current structure, the companies are vertically integrated from generation through distribution. Exploiting their pooled generation units (GENCOs), these companies supply power to their native load -- distribution companies (DISCOs), and municipal utilities (MUNIs). The DISCOs and MUNIs in turn supply all residential, commercial and industrial customers.

Given current operating arrangements, market interactions are dominated by these vertical companies. Most customers in New England are served by their native utility. Rates are regulated on the "cost of service" of their utility -- accounting for the joint operations and savings associated with belonging to NEPOOL. Wholesale wheeling and economic interchange may lower the cost of power to an integrated company and its customers; however, shopping for such economic interchange is left up to the utility and/or the Pool. Physical transactions (the flow of electricity to the customer) and financial transactions (from the customer to the generating utility) are conducted through the vertical companies.

C. Alternative Operating Arrangements[6]

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C. Alternative Operating Arrangements[7]

[7] The material in the section which follows is derived from Hartman and Tabors, "Optimal Operating Arrangements in the Restructured World: Economic Issues" Cambridge, MA. Massachusetts Institute of Technology MIT/LEES Working Paper

The following discussion presents three snap shots of possible future organizational structures for the New England power system. These models are based on discussions and experiences in the United States and elsewhere over the structure of the industry that can best accommodate a desire for increased competition. This move toward greater competition traces its roots to the initiation of Section 210 of the Public Utilities Regulatory Policy Act of 1978 (PURPA) which required regulated electric utilities to purchase the electrical energy of qualifying non-utility generators at an avoided, or "but for" cost. The Energy Policy Act (EPAct) of 1992 provided the next step in the process by defining a class of generators, Electric Wholesale Generators (EWGs), who had the additional right to request and receive a price for transmission service from any regulated utility. The EPAct effectively requires that transmission facilities owned by utilities be accessible to third parties . The FERC is presently struggling with the pricing of the use of these facilities and with requirements for maintaining physical system security and stability under all foreseeable conditions.

The three alternative market models under consideration in a restructured electric industry are:

•Mandatory Pool

•Bilateral

•Hybrid

The first alternative for restructuring the industry is Mandatory Pooling. For our purposes, we define Mandatory Pooling as follows:

•Functional unbundling is implemented across generation, transmission and distribution. This functional unbundling may involve corporate divestiture of assets across all three levels. However, for our current discussion, complete divestiture is not required. Arms-length transactions are required, however they may be implemented. Most importantly, the ISO shall have no identifiable financial interest in the sources of generation or in wholesale or retail distribution.

•The ISO functions as the primary market maker in the following ways:

•It is responsible for the operational efficiency and integrity of the system;

•It purchases power from <u>all</u> generating units (utility generators, IPPs and QFs);

•It sells power to <u>all</u> wholesalers and some end users (DISCOs, MUNIs, residential, commercial, industrial);

95-001, December, 1995.

•It therefore clears the market for power over the grid;

•It manages and facilitates non-discriminatory access;

•It performs financial settlements; and

•It provides transparent spot prices to al market participants.

•All generating units nominate energy products and services for sale to the ISO.

•Those units whose nomination bids are below the system marginal cost as calculated by the ISO will sell their power.

•Those units whose nomination bids are above the system marginal cost as calculated by the ISO will not sell their power.

•Optimal bidding strategy will encourage the generating units to nominate power at their marginal cost.

•Hence, the supply curve for power will be the system-wide optimal dispatch schedule.[8]

•The ISO will be a monopsonist in the market for generated power and a monopolist in the market for distributed power.

•The ISO will therefore be regulated, either cost-based or incentive-based.

Notice that under this version of Mandatory Pooling, there is **no option** for direct bilateral trades among any of the market participants. All trading is accomplished through the ISO which acts as the market maker.

Our second alternative operating design for restructuring the industry is pure **Bilateral Transactions**. For our purposes, we define the Bilateral Transaction operating arrangement as follows:

•As with Mandatory Pooling, functional unbundling is implemented across generation, transmission and distribution. This functional unbundling may involve corporate divestiture of assets across all three levels. However, for our current discussion, complete divestiture is not required. Arms-length transactions are required, however they may be effectuated. As before, it is most important that the ISO has no identifiable financial interest in the sources of generation or in wholesale and/or retail distribution.

•The ISO simply operates the grid and implements power transactions negotiated by other parties.

[8] See Schweppe, et. al., [1988]. This assumes that the structure of generation is sufficiently competitive such that no supplier can exercise market power so as to affect the system marginal cost curve.

•The ISO is responsible for the operational reliability and security of the system;

•To meet its responsibility for operational reserves, the ISO enters the market to contract bilaterally for both capacity and energy;[9]

•In meeting its responsibilities to manage the transmission system, it purchases energy and capacity (ancillary services) from generating units (utility generators, IPPs or QFs) selling into the bilateral market;

•It manages and facilitates non-discriminatory access;

•It may own or lease the transmission facilities; and

•It will be regulated.

•All transactions are negotiated bilaterally between generating units (and/or their aggregators) and customers (and/or their aggregators).

•Markets clear based upon the aggregation of individual transactions;

•Terms of the negotiations are communicated (quantities) to the ISO, who will implement the transactions;

•Private parties perform financial settlements; and

•Private parties provide market information to market participants.

It should be clear that we have posited, **for discussion's sake**, two basic alternatives that embody two polar positions. Under the first operating arrangement, no bilateral trades are allowed. In the second, the only transactions allowed are bilateral, including those of the ISO. We make the alternatives this distinct in order to highlight the different implications for economic structure, conduct and performance induced by each arrangement.[10]

D. Candidate Products and Services in the Restructured World

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[9] In so doing, the ISO will create a type of mini-pool of its own limited resources. This will be accomplished in the bilateral market, where the ISO must compete for resources in the same manner as any other aggregator.

[10] In reality, many proposed operating arrangements are hybrids with different mixes of these two **basic** arrangements. Unfortunately, many of these hybrid arrangements are called "Mandatory Pooling" or "Bilateral Transactions", which only confuses comparative discussions. We have scrupulously defined our operating arrangements as polar extremes to avoid the confusion that arises with attributing the characteristics of a hybrid system to one of our two **basic** operating arrangements. We address hybrid arrangements in Section 5.

A variety of the products and services that we expect to be produced and sold in the restructured world are identified in Table 1. We have grouped them into the following functional areas: generation, transmission, distribution and financial.

TABLE 1
HORIZONTAL MARKETS
Candidate Products and Services

Generation
- Energy
  - Primary energy supply to end users
  - Short, medium, long-term product markets possible
  - Load/seasonal related product markets possible
  - Load Shedding / DSM
- Ancillary Services
  - VAR Support
  - Frequency Support
- Capacity
  - System reserves
  - Long term/ short term

Transmission
- Energy
- System Coordination
- Transmission Constraint Mitigation (out of merit dispatch)

Distribution
- Megawatt hours
- Negawatt hours

Financial
- Contracts facilitating transaction

We have designated a variety of generation products and services. By primary energy supply, we mean real power which provides energy to end users. We foresee that primary energy products will be differentiated: by delivery horizon (short-term, medium-term and long-term products); by system conditions (load level and seasonally-differentiated products); and by source (generation versus DSM or load-shedding products/services). Ancillary services will be those purchased by the ISO, including reactive power to maintain system voltage (VAR support) and

Automatic Generation Control (AGC) functions to automatically balance energy entering the system to maintain frequency at 60 Hz (Frequency support). Capacity services will include a hierarchy of system reserves ranging from spinning reserves to system reserve margin.

The transmission services include basic transmission of energy, system coordination and transmission constraint mitigation when needed. Distribution services involve the direct supply of real power (megawatt-hours) or its substitute (load shedding or negawatt-hours) to the end users who are not large enough to negotiate supply directly with the producers. Finally, financial services will be needed to facilitate the physical power transactions.

E. The Implications of Each Operating Arrangement for Market Structure, Conduct and Performance

The current industry structure allows for internal exploitation of vertical efficiencies (i.e., within-firm coordination of diverse generating facilities with customers exhibiting diverse load patterns). Proponents of vertical consolidation invariably argue that such internal exploitation of efficiencies should be the dominant concern in complex, capital intensive, network industries like electric power.[11]

In terms of vertical structure, both of the proposed restructuring alternatives are more similar to one another than they are to the current structure. They both sever the existing vertical structure by functionally unbundling transmission from generation and consumption (distribution). The proponents of both alternatives argue that such vertical de-integration will be welfare improving.[12] De-integration will eliminate the ability of the vertically integrated firms to exclude participants from the network. Because scale and scope economies allow for market contestability in segments of the network, de-integration will enhance contestability and competition in those segments. Finally, it is argued that such increased contestability and

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[11] For example, Baumol, Joskow and Kahn [1994] state, "there are cost savings to be realized when the two functions [generation and transmission] are combined under unified management, stemming primarily from joint planning of investment and efficient dispatching (determining which generators should be run to meet electric demand at any point in time), rather than relying on markets to coordinate the performance of separate entities. The existence of these complementarities between generation and transmission is the primary reason why, until recently, those two functions have been performed by single, vertically integrated entities in virtually every electric power system in the world."

Spulber [1989] refers to these economies as "economies of sequence", focusing upon the cost reductions that result when a single firm coordinates sequential production activities.

[12] They point generally to the experience in the telecommunications, transportation and natural gas industries to support this position.

competition will not compromise the operational integrity of the network.[13]

However, the proponents of each alternative disagree (sometimes exercisedly) about the means by which the de-integration should be implemented. The proponents of operating arrangements similar to our Mandatory Pooling arrangement have focused upon the easy transition from the current structure to Mandatory Pooling, in terms of institutions, operation and information.[14] The proponents of Bilateral Transactions have argued that the reason the transition to any version of Mandatory Pooling is so easy is that it differs very little from the current system and therefore inherits much of the present system's competitive inertia.

Because vertical considerations do not help us differentiate between these two alternative operating arrangements, we turn to horizontal market characteristics to draw normative distinctions. Specifically, we examine the economic structure, conduct, and performance, induced by the two alternative arrangements in electricity markets.

Table 2 summarizes the principle structural differences arising with the alternative arrangements. In Table 2A, we enumerate the participants (suppliers and customers) that will arise in each of the horizontal markets identified in Table 1. For example, under the current industry structure, all generating facilities (utility-based GENCOs, QFs and IPPs) can be counted among the suppliers of generation products and services. DSM-program participants should be counted among the suppliers of energy, through load shedding. A single entity provides transmission services, another the distribution services. Together they provide the transport function to the local native load. LDCs and MUNIs within the local network to supply energy to most native residential, commercial and industrial customers.

[13] Successful experience with power pools and wholesale wheeling has demonstrated that vertical integration is not required to achieve the complementarities identified above by Baumol, et. al..
[14] See CPUC [1995a].

Table 2: Structural Differences Across Horizontal Markets

A. Number of Competitors

SUPPLIERS

	Current Structure	Mandatory Pooling	Bilateral Transactions
Market Generation			
Energy	All Gencos/DSM		Gencos, DSM, Aggregators
Ancillary Services	Utility Gencos in Pool		Gencos, DSM, Aggregators
Capacity	Utility Gencos in Pool		Gencos, DSM, Aggregators
Transmission	1 (Pool)	1 (ISO)	ISO, Gencos, DSM, Aggregators
Distribution	LDCS/MUNIS		LDCs/MUNIS/Aggregators

BUYERS

	Current Structure	Mandatory Pooling	Bilateral Transactions
Market Generation			
Energy	Utility Gencos	1 (ISO)	ISO, Gencos, Utility Cusomers, Aggregators
Ancillary Services	Utility Gencos	2 (ISO)	
Capacity	Utility Gencos	3 (ISO)	
Transmission	Utility Gencos	1 (ISO)	
Distribution	Utility Customers	Utility Customers	

0

The buyers under the current system can be characterized as follows. Utility generators (GENCOs) purchase energy products and services through wholesale wheeling from other GENCOs under a variety of interchange schedules. These GENCOs can also be thought of as purchasing transmission services from individual transmission owners or from the power pool. Generation products and services use the grid, and energy prices include the regulated costs of the transmission assets utilized. The residential, commercial and industrial customers purchase distribution services from the LDCs and MUNIs.

Under our Mandatory Pooling arrangement as defined above, the number of participants supplying energy products and services will not change. Existing GENCOs (including QFs and IPPs) will continue to supply generation products and services, now to the ISO. LDCs and MUNIs will supply energy to end users. However, the participants on the demand side of several horizontal markets have narrowed considerably from the current structure. The ISO acts as a regulated monopsonist, the regulated single buyer of generation products and services. The ISO then turns around and acts as a regulated monopolist, the single seller of energy services to LDCs and MUNIs. In the process of selling these energy services, the ISO is the single buyer of all transmission services identified in Table 1.

Under our system of Bilateral Transactions, the number of participants increases considerably in all horizontal product/service markets. In the markets for generation products and services, the GENCOs and DSM suppliers are augmented by product/service aggregators. In the market for transmission services, the single provider (the ISO) is now augmented by all utility GENCOs and aggregators who can supply system support and ancillary services. In the distribution market, the LDCs and MUNIs are also augmented by aggregators.

On the demand side of each horizontal market, the monopsony position held by the ISO is eliminated with Bilateral Transactions. GENCOs, utility customers and aggregators can buy (and resell) generation, transmission and distribution products and services independently of the ISO.

In summary, under Bilateral Transactions, a greater number and diversity of competitive participants are active in each of the horizontal markets than exist today or under Mandatory Pooling.

In Table 2B, we identify other structural differences inherent in the alternative operating arrangements. In terms of horizontal scale and scope economies, there is little to differentiate either pooling arrangement from the current structure. The existing scale and scope economies in generation are exploited fairly quickly with current technologies. Transmission and distribution will remain natural monopolies under all three systems. Over the last 30 years, scale and scope economies have been achieved most significantly through vertical coordination of diverse capacity and load. The continued exploitation of vertical scale and scope economies will be accomplished similarly to the current structure and under Mandatory Pooling. In both cases, these economies are exploited by the single pooling agent -- either the vertically integrated utility/power pool or the ISO. Under a system of Bilateral Transactions, the vertical economies will be exploited by any set of transactors and a variety of aggregators.

Recent empirical work suggests that a minimum efficient scale (MES) for vertically integrated electric utilities is approximately 20,000 GWh of sales, with a 95% confidence interval of 10,000-35,000 GWh of sales.[15] Furthermore, there is some evidence that firms which exploit vertical

[15] See Hartman [1990].

Table 2: Structural Differences Across Horizontal Markets

B. Other Structural Differences

	Current Structure	Mandatory Pooling	Bilateral Trading
SCALE AND SCOPE ECONOMIES			
- Horizontal	←	Similar	→
- Vertical	Accomplished Thru Pool	Accomplished Thru ISO	Accomplished Thru ISO and Aggregators
MINIMUM EFFICIENT SCALE	For vertically Integrated Firm, 10,000-35,000	Equal Relevance	
BARRIERS TO ENTRY			
-Gencos -- IPPS/QFS	Entry Difficult, Given Utilities	Less Risk Given Transparent Price	More Risk, More Initiative
-Gencos -- Traditional	←	No Preference	→
-Transco/Gridco/ISO	←	Similar	→
-LDCs		Less Risk	More Risk, More Opportunity
-Aggregators	Limited, Muni-Lites	None -- No Room for Arbitrage	Wide Open
SOURCES OF EFFICIENY GAINS			
- Wholesale Wheeling Only		+	
- Coordinating All Divergent Load With Diverse Capacity			+ 0

efficiencies through tight power pools, the operation of which approximates the single management of a firm, reveal MES much smaller than 20,000 GWh of sales.[16] These findings are equally relevant for each alternative operating arrangement and suggest the following conclusions.

1.Scale and scope economies will be captured through the vertical coordination provided by the ISO and/or aggregators. Everything else being equal, increased economies will occur until the size of the grid reaches approximately 20,000 GWh of sales.[17]

2.These economies can be captured through <u>either</u> an ISO or an aggregator. If the ISO, under Mandatory Pooling, is to be the efficient coordinator of diverse generation capacity with diverse customer load, it must be structured with the financial incentives to do so. Under Bilateral Transactions, an aggregator or a group of aggregators will have the financial incentives to be efficient.

3.Under either system, the load must be large enough to capture the scale and scope economies that are possible.

In terms of barriers to entry, we foresee that there will be no important differences under

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[16] For example, Hartman [1990] finds that utilities that are commonly-owned through a power pool and centrally dispatched reveal a MES of 12,000 GWh of sales.

[17] This estimate of MES is probably too large, for several reasons. First, as stated above, this estimate declines for the tightest pools. Second, all of the estimates of MES make use of cost data from a time period when X-inefficiency and cost-based regulation were in effect. We believe that increased competition will reduce costs and MES.

Mandatory Pooling or Bilateral Transactions for traditional utility GENCOs. Entry has not been possible given the existing institutional arrangements which may, or may not, reflect "strategic behavior." Under Mandatory Pooling, there should be far less risk for Non-Utility Generators (NUGs), given the open market and transparent price provided by the Pool[18]. Under Bilateral Transactions, less information will be automatically available. As a result, there will be greater risk for all GENCOs. We believe, however, that there will also be room for more initiative. We feel that the same differences in entry barriers will arise for LDCs across the operating alternatives, for the same reasons. Under the current system, there has been limited room for aggregators (e.g., Muni-Lites), mostly since the Energy Policy Act of 1992. Under Mandatory Pooling, there will be no entry of aggregators, given that the ISO is assumed to be the single aggregator in the system. Under Bilateral Transactions, entry of aggregators is wide open.

Finally, given the transactions allowed under the two alternative operating arrangements, the sources of efficiency gains under Mandatory Pooling are wholesale trades only. Under Bilateral Transactions, any wholesale or retail trades that make economic sense will be allowed. Hence, the sources of efficiency gains include the more complete coordination of divergent load with divergent capacity.

Based upon these structural differences, we expect the differences in conduct outlined in Table 3 . Given that the ISO will implement optimal dispatch on a system-wide basis under Mandatory Pooling,[19] pricing under this pooling alternative will not be much different from the current system.[20]

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[18] Price transparency benefits both buyers and sellers in the market.

[19] See Schweppe, et. al., [1988].

[20] This assumes that the restructured generation segment is sufficiently competitive. For an alternative result in the absence of competition, see Newbury [1995] and Green and Newbury [1992].

Table 3: Differences in Conduct

		Current Structure	Mandatory Pooling	Bilateral Trading
	Pricing	←	Similar →	Greate Diversity and Activity
Behavior				
	Rivalrous	←	Similar →	More
	Collusive	←	Similar →	Less
	Predatory	Higher	←	Similar →
Entry		←	Similar →	Greater

0

Pricing under the Bilateral Transactions arrangement will be much more active and diverse. We believe that the extent of rivalrous and/or collusive behavior under Mandatory Pooling will be similar to that under the current system. Indeed, some rivalry will be eliminated under Mandatory Pooling, given that scheduling of transmission access will be performed entirely by the ISO, rather than among the wholesale parties[21]. Under Bilateral Transactions, there will be greater rivalrous behavior simply because there will be many more and diverse competitors. This fact will likewise make the occurrence of collusive behavior less probable under Bilateral Transactions. In terms of predatory behavior, the fact that vertically integrated firms currently control the entry of non-integrated players at various points of the network guarantees that some predatory and/or exclusionary behavior occurs. This should not be possible under either of the two alternative operating arrangements. And finally, for reasons stated above, there will be more entry under the Bilateral Transactions arrangement than under Mandatory Pooling.

Table 4 summarizes the differences in market performance that we expect under the two operating arrangements, relative to the current arrangement. The operational efficiency of the Mandatory Pooling arrangement is well understood, since it will work much like the existing system.

[21] Again the reader should recall that we have made us of a very distinct strawman definitions of mandatory pooling. See p.4 above and footnote 4.

Table 4: Differences in Performance

	Current Structure	Mandatory Pooling	Bilateral Trading
- Operational Efficiency	Regulated	Similar to Current Structure	Unknown but Believed Similar to Current Structure
- Social Welfare			
Producer Sutrplus (Profits) -- gencos/LDCs		Higher (U.K.)	Related to Perfomance
Consumer Surplus		Similar (U.K.)	Higher (Norway)
- Product/Service Differences		Similar	Greater
- Contract Differentiation		Less	Greater
- Technological Innovation		Similar	Greater

0

Optimal dispatch will be effected over the entire regional transmission area. The potential operational efficiency of the Bilateral Transactions arrangement is not yet known. However, all observers agree that regulators will supervise operations to guarantee that the lights will stay on under this alternative.[22] In terms of welfare improvement, both alternative operating arrangements will generate efficiencies and cost savings. It is an empirical issue of how those efficiencies will be divided between producer and consumer surpluses. If the experience in the UK is any indication, then under our highly stylized Mandatory Pooling arrangements, the savings would be shared only by the producers (the GENCOs and LDCs) and <u>not</u> the consumers.[23] If the experience in Norway is any indication, then under our highly stylized Bilateral Transactions arrangement, the savings will be captured by the consumers rather than the

[22] See Fernando, <u>et</u>. <u>al</u>. [1995]

[23] David Newbery [1995] examines the structure, conduct and performance of the English bulk electricity market since restructuring. He points out that fossil generating facilities were consolidated, for the most part, into <u>only two</u> generating companies, PowerGen and National Power, and that these two GENCOS dominate supply. Based upon structural grounds, he concludes that "the two fossil generators would be able to sustain a non-collusive equilibrium in which prices were well above operating costs" [p. 46]. It is therefore not surprising that over the period since restructuring, he finds that open access increases production efficiency but that none of the efficiencies are passed onto the consumers. He states that "the sharp increase in the gross profit per kWh of the successor companies to the CEGB ... [are] more than offsetting the considerable fall in labor costs resulting from the massive increase in labor productivity, and leading to <u>higher</u> prices despite the fall in fuel costs" [p. 59].
See also, Green and Newbery [1992].

producers (the GENCOs and LDCs).[24] However, the interpretation of the experiences in these two countries must be done very carefully since neither reflects precisely the definitions that we have used in this paper. We contend that the more competitive the market structure and conduct, the better the market performance will be for consumers.

Likewise, as one would expect, product, service and contract differentiation will be greater under the more competitive structure attendant with the Bilateral Transactions arrangement. Finally, while the theoretical and empirical literatures are not conclusive regarding the dominant performance of competitive or oligopolistic markets in terms of innovation, we believe the recent experience in the telecommunications and transportation industries argues for greater technological innovation under the proposed system of Bilateral Transactions.

Before concluding this section, we believe that it is important to mention briefly the experiences in the U.S. markets for natural gas since open access was implemented.[25] Before restructuring, natural gas markets were structured not unlike the Mandatory Pooling system introduced above. Specifically, all producers[26] sold gas (for resale (brokerage) and transmission) to pipelines; hence, the pipelines acted as monopsonists or oligopsonists, relative to the producers. The pipelines in turn resold the gas at retail to local distribution companies (LDCs); hence, in these transactions, the pipelines acted as monopolists or oligopolists. All segments of the industry were regulated, and unregulated bilateral transactions were not allowed between producers and LDCs. The result was an industry characterized by long term contracts (20 years) for product between suppliers and the pipeline and the pipeline and LDCS.[27] Because all segments of the gas industry were regulated,[28] the analogy to Mandatory Pooling is far from

[24] See, for example, Diesen [1994]; Amundsen and Singh [1992]; Loken [1995].

[25] For simplicity, we take restructuring of the U.S. Natural Gas industry to be implemented by FERC Order Numbers 436, 500 and 636, in spite of the fact that a variety of deregulatory activities were ongoing since the Natural Gas Policy Act of 1978. For greater institutional discussion, see Doane and Spulber [1994].

[26] The production segment of the gas industry certainly has been competitive, pre- and post-restructuring. It is certainly more competitive than the generating segment of the electric power industry will be under <u>either</u> Mandatory Pooling or Bilateral Transactions. The Energy Information Administration estimated that there were 12,000 field producers in 1981, and that HHIs in most producing regions ranged from 220 to 620. See Doane and Spulber [1994, pp. 479-480].

[27] Resulting issues of structure and conduct have been well explored elsewhere. Long-term contracts evolved as an alternative to vertical integration, given the opportunism that can arise in negotiations in the presence of transaction-specific irreversible investments in gathering and transmission pipelines. The long-term contracts also helped reduce transactions costs, given the possibility of opportunistic behavior throughout the industry. See Doane and Spulber [1994], Hubbard and Weiner [1986,1991], Joskow [1987], Mulherin [1986a,1986b].

[28] The overall experience with regulation has been well documented. For examples, see

complete. However, notice that the only real difference under Mandatory Pooling relative to the gas industry pre-restructuring is that the GENCOs will not be price-regulated under Mandatory Pooling.

While a number of changes were induced by the restructuring of the gas industry, the most important was the unbundling of the marketing and transmission of gas[29]. Under unbundling, LDCs were allowed to negotiate freely through <u>bilateral</u> <u>transactions</u> with the then deregulated producers. The negotiated transactions were trans-shipped non-discriminantly over the existing pipelines allowing the newly-competitive producer prices to be passed on to the LDCO[30]. The availability of common carriage of gas stimulated entry of many new participants -- brokers, independent marketers and marketing affiliates of existing pipelines -- on both the buying and selling side of the market. Spot markets for product and capacity evolved quickly, while regional markets became national in scope.[31] As spot markets became more vibrant and dense, transaction costs were reduced, futures markets arose, and the strategic need for long-term contracts diminished.[32] We expect that, relative to Mandatory Pooling, a system of Bilateral Transactions will engender in electric power markets the same competitive entry and evolution of spot and futures markets that the restructuring of the gas industry induced.

F. Implications for the Choice of the Optimal Operating Arrangement

We have chosen to frame the discussion with our two polar-extreme operating designs, in order to isolate and make explicit the advantages (and disadvantages) of each. This approach avoids the difficulty of identifying the source of particular advantages when a proposed operating arrangement is a hybrid of our two alternative arrangements.

The advantages of each that we have identified are the following:

<u>Advantages of Mandatory Pooling:</u>

Broadman [1986, 1987], Doane and Spulber [1994] and MacAvoy [1970, 1979].

[29] Of course, an additional issue important was the increased reliance upon competition at the producer end.

[30] We do not address whether these price advantages were passed on to all consumers.

[31] Doane and Spulber [1994] test for and demonstrate the evolution to national markets using measures of price correlation, Granger Causality tests and methods of cointegration. See also Stigler and Sherman [1985], Horowitz [1981], Cartwright, Kamerschen and Huang [1989], Klein, Rifkin and Uri [1985], Granger [1981,1986], Dickey and Fuller [1979], Engle and Granger [1987].

[32] The development of sufficient competition to support the functioning of spot and futures markets eliminated the possibility for opportunistic exploitation of transactions-specific assets. See Carlton [1984]; Doane and Spulber [1994]; and Klein, Crawford and Alchian [1978].

Our Mandatory Pooling arrangement offers a range of advantages in the areas of simplicity and potential operational efficiency. Because it is so similar to today's vertically-integrated utility power pools, the transition would be relatively painless. Institutions currently in place could be transferred organizationally to an ISO virtually in tact. All generators would continue to bid into the pool on an equivalent basis and all wholesalers and/or retail customers would continue to purchase from the pool at the pool marginal cost.

Operationally, the Mandatory Pooling system's greatest advantage is that the ISO has under its control all generating assets and knows the marginal operating cost (or willingness to generate) of each, based on individual bid prices into the pool. As a result, the ISO has the ability to centrally schedule against these bid prices both for generation of energy as well as for provision of ancillary services and transmission constraint mitigation. This allows the ISO to use the least cost resources, as indicated by the bid price, to fulfill any system need.

The final advantage of the Mandatory Pooling structure is that the ISO, through the pool itself, provides a transparent spot market price. This spot price is available to all consumers of the ISO's services (both generators and end users). This price can be used as a clearing value for financial instruments such as Contracts for Differences.

Advantages of Bilateral Transactions:

The advantages of the Bilateral Transactions arrangement all derive from the fact that additional players participate in the market, while the operational integrity of the system is insured by the ISO. Aggregators and repackagers will be significant players in the Bilateral Transactions market model.[33] These entities will actively seek out transactions that will bring buyers and sellers (most likely as groups) into contact, such that the individual preferences of both groups are uniquely met. The usual welfare improvements stemming from competition will result, as suggested by economic theory and as demonstrated by the restructuring experiences in the telecommunications, natural gas and transportation industries.

This increase in the number and diversity of market participants induces two subsidiary advantages, one regulatory and one innovational. Because the Bilateral Transactions arrangement engenders greater competition through the entry of a significant number of new participants (generators and aggregators), far less regulatory oversight should be required in the steady state. Competition is generally more effective in regulating economic behavior than is agency regulation.[34] Likewise, we contend that the increased level of competition fostered by the

[33] As in the restructured natural gas industry.

[34] Of course, some oversight is required even in competitive markets. For example any well functioning market requires clear rules as to what is unfair and deceptive behavior

Bilateral Transactions Model will lead to significant innovation in both the products and services supplied in the industry. The experience in the restructured telecommunication industry is illustrious in this regard. We anticipate examples of this innovation to include energy management and control, and service repackaging. We anticipate these competitive benefits will occur within a reasonable period of time.

The disadvantages inherent in each structure can be viewed simply as the flip side of the advantages of the other structure. Thus, the Mandated Pooling system is most strongly criticized for its restrictions on bilateral contracts. It is also strongly criticized for its apparent restrictions concerning the entry of participants (aggregators) into the market. The Bilateral Transactions model is most often criticized for its lack of an institutional spot market, and with it a transparent spot price. It is also criticized for its significant break from today's utility operating structure since the ISO will have only quantity information for use in scheduling of transmission transactions, rather than full control of both price and quantity as is true both today and in the Mandatory Pooling alternative.

The Design of a Hybrid System

Clearly, since each operating arrangement has advantages and disadvantages, we can improve upon each by designing a hybrid that includes the advantages of each while excluding their disadvantages. Hence, we would expect that the optimal operating arrangement will be a hybrid. It should take the best of each of the proposals to develop a realistic market structure that will provide both the reliability and security necessary to keep the lights on as well as the economic structure and market behavior necessary to assure the regulators and the Department of Justice that a competitive market does (and will continue to) exist.

What characteristics should this optimal hybrid arrangement have? The hybrid system should allow for both bilateral contracts and for pools. As we have argued, bilateral contracts are critical to insure the openness of market opportunities and create the incentives for the entry of marketers and brokers whose actions will provide the tailored products and innovation in services.

In addition, multiple pools are required in two formats. The first set of pools will be created by aggregators as they purchase supplies and serve their contracted loads. These pools will operate both through bilateral contracting and through spot market exchanges. Each pool, whether required as an energy exchange or privately established by an aggregator, will have a spot price. Economic theory of market behavior tells us that the spot prices of these pools will be

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on the part of market participants.

the same at any point in time and space. A second pool will be required by the ISO to provide reliability, security and the capability to mitigate transmission constraints. This pool will be shaped by the requirements of the ISO to provide these system services. Its size will change with time as increased knowledge of system operations is accumulated and as the ISO and the market develop. We have proposed (in other writing) that this pool will likely be denominated largely in capacity (kW) as opposed to energy (kWh) because the ISO is not a participant in selling in the commercial market; it is only a purchaser of the resources required to keep the system functioning.

This hybrid arrangement can be developed using either our Mandatory Pooling arrangement or our Bilateral Transactions arrangement as a point of departure and modifying each by incorporating the advantages of the other. The result will be a system that provides for market development and evolution while guaranteeing that the level and quality of service demanded by the US consumer.

Ultimately, the hybrid system should be designed so that its operation will reveal the preferences of the system participants. If the advantages of Mandatory Pooling are found to be preferred and to dominate, then over time most transactions will take place through a variant of a coordinated pooling structure. If the advantages of Bilateral Transactions are found to be preferred and to dominate, then over time such transactions will predominate and any centralized pool or energy exchange will wither. As stated by Professor William Hogan, "Despite much high rhetoric to the contrary, the two approaches [mandatory pooling v. bilateral transactions] are not necessarily mutually exclusive, or even in conflict. An attractive option is to embrace both, and give market participants the maximum set of choices."[35]

2. The role of the Independent System Operator

A. Introduction and Overview

The concept of an Independent System Operator (ISO), playing a major role in the restructuring of the US Electric Supply Industry (ESI), has been a part of a series of restructuring proposals beginning with the work of TCA and PG&E in 1994.[36] The concept has gained more attention

[35] Hogan [1995].

[36] Referred to as the NetCoor function in testimony by Richard Tabors before the California Public Utility Commission in September, 1964 and reported in Fernando, Kleindorfer, Tabors, Pickel and Robinson, “A Blueprint for Restructuring the US Electric Power Industry” Tabors Caramanis & Associates, March, 1995. PG&E presentations by

recently including a set of FERC discussion panels on January 24, 1996. The objective of this section of the appendix is to discuss, from both an engineering and a market perspective, the functions of an ISO, and to discuss the concept of *independence* in this context.

The concept of an Independent System Operator is becoming widely accepted. Professor William Hogan in a recent article in *The Electricity Journal* stated “There are significant advantages in the approach [the ISO] but the key to success will be in a careful specification of the ISO’s functions and responsibilities. Simple independence is not enough; the ISO should support an efficient, competitive market.”[37] We agree in spirit, if not in precise format, with this summary statement. Defining the roles of the ISO are critical to the operation of an institutional player in the complex electricity supply industry. Supporting an efficient and competitive market can, however, be interpreted in many ways.

The ISO must be a regulated player in a largely unregulated commodity market for both economic and engineering efficiency to be assured. Not only is this independence critical to ensure that the functions of the market proceed without any prejudicial transactions, or the potential for those transactions, but it is critical to provide the proper economic incentives for the ISO to maintain system reliability and provide for operation of the transmission grid. It is argued further that the functioning of the ISO does not require that, indeed should not require,[38] it be the administrator of a wholesale spot market and that, for some circumstances, the ISO operations may be hindered by such a structure. This will occur at times of high demand when the majority of transactions are locked up through bilateral contracts leaving this administered spot market too thin to provide the capacity resources necessary to maintain reliability and stability of the grid. On the other hand if there were only a few bilateral contracts, the ISO-based wholesale spot market would be more adequate.

Engineering realities play a critical role in the manner in which the ISO will operate. An electricity commodity market can and will work very efficiently in the time frame greater than 1 hour, possibly greater than 15 minutes as increased computation and communication capabilities become available. The task of the ISO is to plan for and implement the operational decisions required to “keep the lights on” in the time frame *of less than 1 hour*. The characteristics of these operations are vastly different from those within which the commodity market operates. The commodity being traded in the commercial market is energy, kWhs. In the past, we were conditioned to believe that these kWh were all equal but we now come to realize that they come in different flavors as a function of time and location and may even be differentiated by their source of supply (green v. nuclear, etc.). Without regard to the attributes, the commodity, a kWh, is tradable and is a unit of *energy* that is consumed in our offices, factories and homes.

There is a second set of functions within the electric supply industry that are essential to the operation of the commercial market. Energy consumers receive these services bundled with the kWh, specified levels of: reliability, voltage, frequency and harmonics. It is critical to note that while consumers see these functions inextricably bundled with the kWh, they can be provided by a variety of means and certainly by a variety of suppliers. This creates a second market within

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James Mecias before the California Power Market Working Group, December, 1994 and before the California Public Utility Commission, February, 1995.

[37] William W. Hogan “ A Wholesale Pool Spot Market must be Administered by the Independent System operator: Avoiding the Separation Fallacy”, *The Electricity Journal*, December, 1995, pp 26.

[38] In California ISO is explicitly separated from the power exchange, i.e. the wholesale spot market.

the electric supply industry. This second market is different, however, in that its basic unit is not the kWh but the kW. It is a market in, predominantly, short term capacity.

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Figure 1

Figure 1 provides a graphical representation of the two components of the electricity supply industry. The left side of the figure represents those functions that can be provided in the commodity market while the right side shows the market for capacity services. We contend that the right side is the domain of the ISO.

B. Maintenance of System Reliability and Stability

The role of the ISO is to maintain system reliability and stability -- which requires operation and control of the transmission grid within the ISO's control area. The ISO is a heavily FERC (performance based) regulated, profit making entity that owns no assets beyond the computers and office space of its staff.[39] It contracts for capacity to provide reliability and stability, it leases the transmission assets from their current and future owners, and it charges a regulated rate for the service it provides.

There are five functional areas in the electric power system as it exists today and as it will continue to exist in a restructured, market-based world. Today these functions are all a part of the vertically integrated utility. In the future, these functions will be separated into competitive (market) and monopoly (regulated) activities.

[39] As is discussed below, the ISO could own the transmission facilities for the region over which it is responsible. A more straight forward alternative is for the ISO to lease all transmission facilities.

These five functions are:

Supply: The provision of both kilowatt hours through generation and the provision of interruptible demand—negawatt hours.

Supply Aggregation: The function of developing, through ownership or through contracts, the mix of supply assets that best match the load.

Demand Aggregation: The function of developing through contracts a mix of customers.

System Operation: The function that provides for the reliability and stability of the power system and its transmission network.

Consumers: The customer—either in the aggregate or in the individual—of the reliably and securely delivered commodity, kWhs.

Even the regulated activities will be subject to market forces through competitive asset acquisitions and through performance based regulation. The structure of the supply industry presented here is one in which competition extends to all stages in the chain of electricity supply. Present electric utilities will unbundle, and, in all likelihood rebundle, their currently bundled product and service components.

Figure 2 depicts the future structure of the new electricity supply industry. The commercial functions of purchasing and selling electric energy are transacted by the individual market participants, including independent generators, marketers, load aggregators, and consumers. The physical operations of ensuring system reliability, system security, and system stability are provided by an independent, performance based, regulated network coordinating entity called an independent system operator (“ISO”).

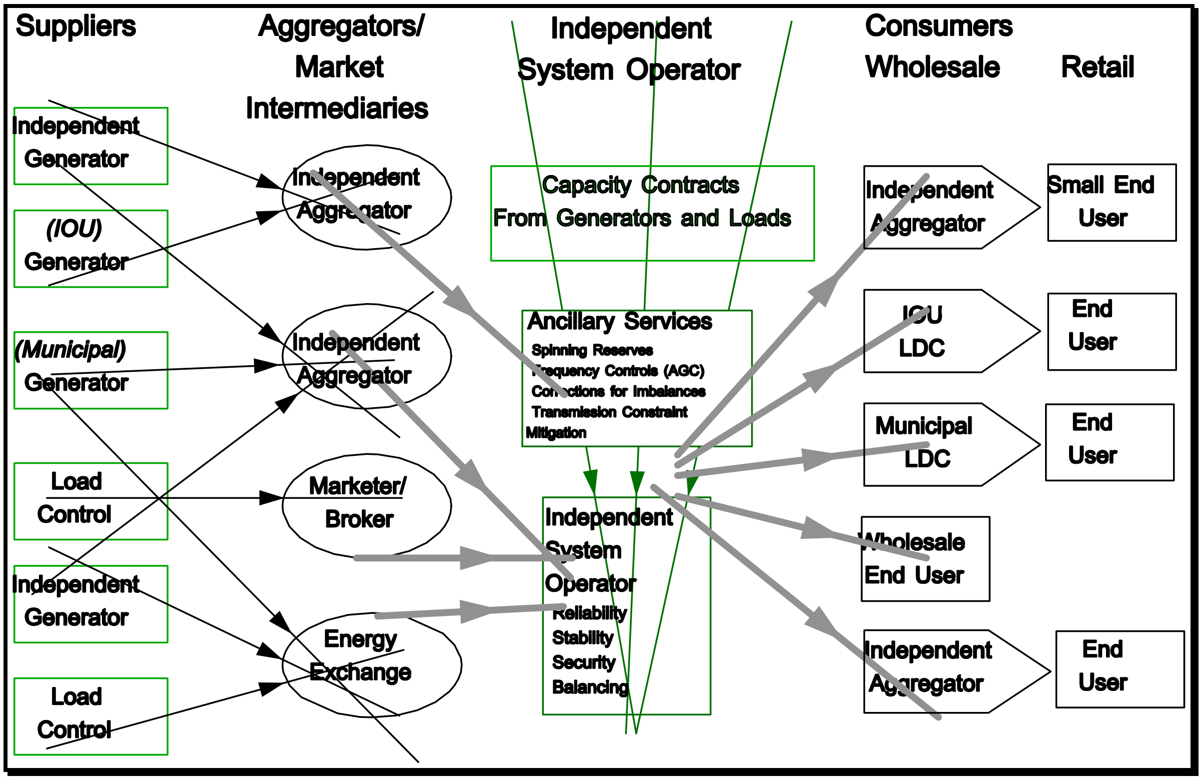

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Figure 2

This model envisions an electricity marketplace where customers have a choice among electricity suppliers, and where generation companies and energy service companies will be deregulated. Delivery services will continue to be provided at regulated prices by regulated transmission and distribution utilities.

We contend that the role of the ISO should be to coordinate all transmission operations, both to facilitate and maximize utilization of the grid, and to insure system stability and system reliability. Open, non-discriminatory access for transmission will be required for all transmission facilities, which could either be owned by private transmitting utilities and leased to the ISO, or be owned by a single regional transmission company and operated by the ISO.

The purchase and sale of spot power and its resulting dispatch of generators will be handled by competing market participants. The ISO will coordinate the hour-to-hour, cycle to cycle operation of the system and will also coordinate and supply, to the extent necessary, ancillary services to ensure reliable operation. This model envisions a future world of bilateral contracts between generators, marketers, and customers which define the terms, conditions, and prices of all power delivery.

The ISO will be, we argue, an independent agent that has no corporate or business relationship with any market participant. It is directly responsible for insuring the reliability and security of the bulk power market. In terms of regulation, the ISO will be regulated by the FERC. Under this model, market participants will have no authority over the ISO. This arrangement is in dramatic contrast to the pattern seen in the major power pools like Pennsylvania, Jersey, Maryland (PJM) or NEPOOL today where the operations are heavily intermingled with the market activities and in which the institutions themselves are the children of the utilities that they serve.

The ISO will operate within a limited market in *capacity* in order to maintain reliability and stability of the overall system. As such, the ISO will contract for needed supplies of capacity (and in highly limited circumstances, energy) from any source willing to sell into this distinct, operating market. The ISO will be responsible for making the necessary arrangements for capacity to account for unanticipated swings in demand and unanticipated changes in generation through contractual arrangements with supply or demand control resources.

Local distribution companies ("LDCs") will operate and maintain the distribution system, and will have the obligation to *connect* all customers in their franchise or service area to the system.

Energy service companies ("ESCOs")[40] will be the primary interface with the customer and will act as the intermediary between the customer and the generators that provide power. It is envisioned that ESCOs will contract with generating companies, transmission companies, and distribution companies to purchase power and delivery services which will then be packaged and resold to customers. Competition among ESCOs will be relied upon to provide competitively-priced retail energy services to customers, and competition among generating entities will yield competitively-priced bulk power for purchase by the ESCOs. Customer choice and the competition among ESCOs will yield a large variety of pricing and service options for customers, including risk management.

One form of ESCO--the marketer--transacts with suppliers, wholesale customers (including load aggregators), as well as directly with other ESCOs and retail customers. Marketers will take title to power and resell it on the wholesale market. Load aggregators will bundle load and services to deliver to a range of potential customers. The role of load aggregators is primarily to assist customers in joining together to increase their buying power, optimize their load profiles, and otherwise take better advantage of retail competition.

In addition to these market participants, other market players that provide additional services will emerge as well. Some ESCOs could bundle a power sale with metering and associated equipment services. Customers will pay the ESCO directly for these services.

[40] We recognize that the term ESCO has commonly been used to narrowly refer to companies performing energy management and cogeneration services; here our definition is much broader and includes a full range of energy-related services.

C. Operational Functions of the ISO

We believe the ISO should be a FERC, performance based regulated entity that either owns no physical assets but leases them from owners (thereby controlling the regional transmission system) or owns all transmission assets.[41] Through competitively secured capacity contracts, the ISO controls only those physical generating assets necessary to provide system stability and security and to provide for those ancillary services not provided directly by the market participants themselves. The ISO is responsible for the physical delivery of the energy nominated by suppliers and buyers who utilize the transmission grid and for providing the information on actual injections and withdrawals relative to nominated transactions that are needed for all parties to clear their transactions.

The ISO will be required to contract for capacity to provide system services from any generators or other entity that can provide them. This includes capacity for all levels of operating reserves, the ability to provide reactive power where needed within the grid, AGC capability as required to maintain system frequency, and when needed, the capacity to cover losses and provide energy for balancing. The ISO will have call contracts in place, by which the ISO purchases the right to call upon a unit to provide each of these functions. When called, the unit's owner receives additional compensation to cover the operating costs.

Under the model described in this appendix, generation is explicitly not subject to central dispatch. Supplies (both generation and demand control) are acquired and dispatched by their aggregators. There may be multiple "pools", each with its own resources and with its own contracts with buyers that need to be supplied. This will mean that there is some small chance that generating units *may* run somewhat differently than they do today. Their future operation will be conducted to match the efficient operating requirements of the load aggregators.[42]

Along with the individual aggregators, who will work to dispatch their own assets so as to fulfill their contracted load requirements at minimum cost, the ISO will dispatch its assets, to the extent necessary, to provide system reliability and security and to minimize the ISO's total cost of operations. At the margin in a spot market with posted prices as will occur with an Electronic Bulletin Board (EBB), for instance, all aggregators will be trading to provide energy at the lowest cost. This spot market trading through an EBB will have the effect of achieving equivalent or superior efficiencies to those that are now found in central dispatch.

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[41] See section 3 of this appendix for a more complete discussion. Note here that in New England the first option, leasing, appears more likely to be easily implementable given the complexities of ownership in the region. Even under these circumstances, however, there is a clear start-up issue.

[42] It is important to note that in the presence of perfect information, all generators would behave essentially as they do today with each aggregator dispatching according to its economic requirements and all transactions clearing through the open spot market.

D. The ISO and Ancillary Services

In the model of the restructured industry described in this paper, ancillary services will be available unbundled either in the market or from the ISO. Ancillary services cover a range of services some of which must be handled centrally. As an example, AGC functions need to be handled centrally and will be contracted for by the ISO and provided to, and paid for, by all who use the grid. On the other hand, losses can be handled as efficiently by a bilateral market as they can by the ISO. They will be supplied either by the two parties in a transaction or purchased from a third party. As a second example, reserves are required in the system to maintain reliability. The ISO will be one source of supply of reserves, but a given aggregator could choose to hold reserves within its "pool" to cover contingencies in supplies. These reserves could be in the form of additional supplies or in the form of interruptible load. An aggregator holding its own reserves will be required to nominate these to the ISO along with the transactions, so that the ISO can call upon them if and when needed during the operating time frame.

Most of the functions that we refer to as ancillary services are "common goods" in that once supplied to the grid they can not be denied to anyone else who is connected to the grid. These services are frequency control, voltage control and VAR support, spinning reserves and transmission constraint mitigation services. All users of the grid benefit from the provision of ancillary services and it is not possible, generally, for any user to choose to opt out of receiving these services.

Conversely, however, it is possible for a wide range of entities to provide ancillary services to the grid. Many of these services are provided by generators though some can also be provided through demand management or through capital investments. Interruptible loads are equivalent to generation in terms of spinning reserves. Investment in technologies such as Static VAR Compensators are equivalent to VARs being provided by a generator. Frequency control, on the other hand, must come largely from generation.

While the ISO may be the major purchaser of ancillary services, the assets, from which many of these services are derived, have additional (and generally superior) values within the commercial energy market. As a result, this model will provide for competition between asset uses, only one of which is ancillary services, and thereby offer the opportunity for significant market efficiencies.

Through operational control of the transmission grid and operational control of the contracted assets in its portfolio, the ISO has the physical control needed to maintain system reliability, security and stability. Further, the ISO has the incentive to minimize its total cost of operations, trading-off between payments for lease of physical facilities or payments for system services and transmission constraint mitigation.

E. The ISO: Reliability Requirements

Any model for a restructured electric supply industry must be able to ensure that reliability will be maintained to meet consumer demands. Reliability should not, however, be confused with a customer's desire to pay less per unit of energy when they choose to interrupt their load at times of high marginal cost on the system. Customers can be given a choice of service levels without limiting system reliability. The debate which seems to have emerged between customer choice and reliability is based on a false assumption — customer choice does not offer customers differing levels of reliability, but rather, differing levels of service in terms of quality and curtailability.

In our model we have assumed that the NERC will continue to provide guidelines for reliability within the US. In addition individual suppliers and aggregators may choose to set criteria more stringent than NERC. The ISO will maintain industry standards as agreed to in the region. These standards can be met through both available supply capacity and demand response. Hence, in a competitive market, reliability is maintained much as it is today, through a set of individual entities purchasing and/or providing resources to maintain the integrity of energy delivery within the system.

As the basic services for electricity are unbundled, some customers will choose differing levels of service quality and curtailment, as presently occurs with natural gas service. Customers will enter into long-term customized contracts to obtain priorities and curtailment privileges based on their individual risk profiles. Customers will take advantage of options for load management, such as accepting interruptions of electric service or accepting temporary voltage reductions where feasible, to reduce their costs when it is in their economic best interest to do so. This response will provide additional flexibility within the system to guarantee that aggregate reliability of the electric supply system will be maintained at or above NERC standards.

Some of the arguments against restructuring and unbundling have implied that this flexibility will reduce the capability of the industry to respond to extreme situations which stretch the industry's resources. There is very little evidence of this in other industries, such as road and air transportation, telecommunication or natural gas. Indeed, when the Northeast experienced extreme winter weather conditions in February 1994, natural gas delivery in the region continued without disruption, whereas many extensive disruptions of electric power supply were experienced, shutting down Washington, DC and other urban centers in the region.

Capacity reserves will be maintained by investors' response to two factors: market prices and reliability needs. When forward market prices increase, investors will see that the demand side of the market is calling for additional energy — as seen in their willingness to pay a premium for longer term contracts (more reliable supplies). As these forward prices increase, investors will enter the market to supply additional capacity. Second, the ISO will be buying contracts for the level of capacity it requires for supplying operational reliability. This market will also show an increase in per unit prices. Again, these price increases will provide information for investors to add capacity.

With the exception of acts of God, it is the responsibility of the ISO to provide for reliability. Dropping load has a cost to consumers and to suppliers and traders whose revenues will be reduced. The responsibility of the ISO will to either be self insured or financially insured to compensate at a pre-agreed-upon level for energy not served. Self insurance may come in terms of a set of interruptible contracts as well as in terms of a cash reserve for such contingencies.

Under true emergency conditions, however, it will always be necessary (as it is today) to have the ability to drop load. Much that is done by pools (such as NEPOOL under it's OP4 and OP7 procedures) will be done by first utilizing any interruptible contracts and voltage reduction then through shedding that represents "equal pain" for all transactors in the affected region. Because the objective is to maintain reliability for the largest number of users, the ISO will have the ability to interrupt when and where needed with the knowledge that the reasons for the interruption and any financial settlement as to its cause will follow as an after the fact bookkeeping activity.

F. Performance Incentives for the ISO and Other Market Players

Within the proposed model of the restructured industry, the incentive for commercial players is economic self interest. Generators and suppliers of demand management are in business to compete with their counterparts on the horizontal level. A supplier who cannot supply to a contracted customer, or one selling into the spot market who is not available at times of high spot price, will lose money. The same argument is made for aggregators on both the supply and the demand side of the system. Missing potential sales results in both lost opportunities and lost customers. Penalties for non-performance in contracts represent an additional incentive and may offer an additional element in this proposed structure.

The system functions by the ISO receiving nominations from suppliers and/or buyers to inject and withdraw energy from the grid. These nominations are for quantity only. While the shortest transaction period is likely to be an hour, longer term contracts between a supplier and a buyer can also be left as a nomination to the ISO. Based on long and short term nominations for any given hour, the ISO evaluates its expected cost of operation. In the most sophisticated alternative we foresee, these costs will then be fed back to the suppliers and/or buyers who can change their nominations to respond to the cost of system services and transmission constraint mitigation. After a finite number of iterations, the market is closed, nominations are firm, and the ISO proceeds to deliver the contracted energy.

The evidence available for regions such as New England indicates that this level of sophistication in pricing is neither warranted nor necessary (see appendix B). There are few constraints that bind. In the near term it will easily be possible for the ISO to approximate the results of the iterative procedure through evaluation of the expected grid conditions in the region. System services and transmission constraint conditions are highly forecastable *within* the New England region. It is argued that New England breaks into only 2 operating costs regions for either transmission or system services. These regions are active less than 5% of the time and, under current operating conditions, show only a small, though important, difference in costs. Under these conditions a simple postage stamp approach will suffice until more sophisticated calculation methods are required.

The question arises as to whether specific players in the market will choose to rely on the ISO for all non-energy services, i.e. for balancing and for other ancillary services. The resources of the ISO are predominantly capacity -- the ability to cover shortages and the ability to provide voltage and frequency support. While frequency support (AGC) is a continuous function of the system, voltage support is provided on an as-and-where-needed basis. This means, in all likelihood, that these services will be provided out of relatively expensive units given that the units will have a higher value selling energy to the market than they will selling only capacity to the ISO. It will also mean that most aggregators will find it more cost effective to provide their own services when they can, rather than relying on the ISO.

One issue that will remain in development of the actions of the ISO is that of balancing for over and under supply. What happens when a physical transaction differs from that nominated by the supplier or marketer and therefore the generation and load for a given transaction do not balance? We believe that a secondary market will emerge to cover balancing whenever it is economic for individual players to do so just as developed in the natural gas market.

If the physical delivery or removal of energy from the grid differs from that nominated to the ISO, it will be the responsibility of the transactors to either trade, after the fact, with transactors, whose balances were in the other direction or, if necessary because all (or net) trades were deficit during a specific time period, to pay the ISO for reserves that were used to make up the deficit or, conceivably, to be paid by the ISO for the surplus. We have proposed that these deficit and surplus amounts be paid for at the ISO's incremental or decremental cost (plus applicable penalties, in the case of deficits). There should be no advantage available to any transactor from delivering too little or too much to the grid. The resources of the ISO will likely be the most expensive resources available (in that they are being purchased for their capacity value not their energy value). As a result, it will be in the transactors economic best interest to deliver close to the nominated supplies or to locate—based on ISO provided information—an after the fact trading partner as opposed to leaning on the ISO's reserves.

G. Paying the ISO

The ISO will be paid by all users of the grid system. Payment will be based on the quantity of energy (kWh as opposed to capacity, or kW) that is moved on the system. Payment will be based on two terms, the sum of the fixed costs of the ISO, the lease payments or carrying charges on assets, and the operating costs, the contracts the ISO holds to provide for reliability, stability and security. One proposed method (see appendix C) is to have the price charged set as a cap and escalated by the rate of inflation. The cap will be calculated in advance as the expected value of each of the above two terms for a fixed period into the future. The setting of the ISO price cap will be one of the issues of the start-up. The ISO should be provided with a means of covering its costs. If the ISO operates leased lines, the cap is based on lease charges, if the ISO owns lines, then the cap should be based on carrying charges. In all cases, the rates are regulated by the FERC. A price cap structure, provides the ISO with the incentive to operate the system efficiently and to thereby profit by the amount that operating costs are below the price cap.

It is proposed that all prices to users will be known in advance with the ISO accepting some level of risk in writing contracts with users for services supplied.

The incentive for the ISO is to minimize their total cost of operations as this will maximize the difference between their cost and the price cap that they are allowed to collect, and to move as many kWh as are economically and physically feasible, since this will increase revenues through increased volume on the system. The revenues collected by the ISO, per unit of energy transmitted on the grid, will be regulated to remain under the price cap. Any over recovery will be adjusted against the next time period's price cap. The ISO may choose to under recover, relative to the price cap, if it can show greater profit by moving more energy at lower costs to users.

H. Summary and Conclusions

The independent system operator has become a key element in the restructuring of the US electric supply industry. While the vocabulary is constant, the definition of the roles and rewards change as one moves from a picture of the ISO as the market maker / coordinator to that of the ISO as only being responsible for keeping the lights on. This section has provided a background to both the engineering and the economic efficiency issues that argue for the ISO maintaining control of the operational market -- less than an hour -- while having no responsibilities for operation of the commercial, commodity market.

3. Alternative Patterns of Transmission Ownership and Control

There are, we believe, two patterns for ownership and control of the transmission system in New England which are functional, given the realities of the system. The first of these is outright ownership and the second is a required lease of all transmission assets from owners to the ISO. In either case, the ISO must have full control of all transmission assets to guarantee the reliability and security of the overall energy delivery system in the region. The discussion which follows provides an overview of the advantages of each of these proposed alternatives.

A: ISO Leases All Transmission Facilities

In this alternative, the ISO leases all transmission facilities from owners. Any entity can build and own transmission assets and lease them to the ISO. Initially the ISO negotiates, with FERC supervision and approval, a lease rate for all transmission assets currently in operation within the New England Grid. These initial leases provide, owners of the assets with what is judged by the regulatory structure to be a fair return on investment. In this manner all transmission owners will be paid the value of their transmission assets while relinquishing operational control to a single functional organization, the ISO. The ISO will assume full responsibility for maintenance and operation of the assets such that no untoward damage is incurred in the operations of the asset.

After the system has been in operation and when the economics of the ISO show that increased transmission capacity at a specific point in the grid will minimize the ISO's costs (the cost of leased assets compared with the payments for the contracted system services required for transmission constraint mitigation), the ISO will develop an open bid for entities to build and lease new transmission assets.

B. The ISO Owns All Transmission Assets

The proposal under which the ISO owns all transmission assets is directly parallel to that described above with the exception that assets are transferred through ownership from the current utility to the ISO. Payment may be based on a type of mortgage, held by the current utilities, or through a new financial structure established against the credit of the ISO. Under the ownership option, the ISO would choose when and where to strengthen the system and would be responsible for the financing and payment under FERC supervision.

C: Conclusions and Recommendations

Transmission assets represent a significant component of the assets of many of today's electric utilities. At the same time they are frequently, jointly owned, and are part of a larger grid within a single control area such as is the case in New England. The valuing of transmission assets within this proposed structure will be a thorny issue. The proposal in which the ISO leases all assets and is responsible for the economic decisions associated with the expansion of new assets represents, we believe, a highly workable means of dealing with the engineering realities of the network while maintaining the economic benefits of current and future ownership of the transmission capital stock.

Establishing an initial value for the purpose of a lease or a direct sale will require a set of rules that provide the owner with a fair rate of return on the asset or a fair market value. These rules will, we believe of necessity, be established and supervised by the FERC.

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APPENDIX B

TRANSMISSION PRICING METHODS

Michael C. Caramanis

Figure 1 provides a graphical representation of the two components of the electricity supply industry. The left side of the figure represents those functions that can be provided in the commodity market while the right side shows the market for capacity services. We contend that the right side is the domain of the ISO.

B. Maintenance of System Reliability and Stability

The role of the ISO is to maintain system reliability and stability -- which requires operation and control of the transmission grid within the ISO's control area. The ISO is a heavily FERC (performance based) regulated, profit making entity that owns no assets beyond the computers and office space of its staff.[11] As is discussed below, the ISO could own the transmission facilities for the region over which it is responsible. A more straight forward alternative is for the ISO to lease all transmission facilities. It contracts for capacity to provide reliability and stability, it leases the transmission assets from their current and future owners, and it charges a regulated rate for the service it provides.

There are five functional areas in the electric power system as it exists today and as it will continue to exist in a restructured, market-based world. Today these functions are all a part of the vertically integrated utility. In the future, these functions will be separated into competitive (market) and monopoly (regulated) activities.

These five functions are:

Supply: The provision of both kilowatt hours through generation and the provision of interruptible demand—negawatt hours.

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APPENDIX B: TRANSMISSION PRICING METHODS

B.1 Introduction of Marginal Cost Pricing Concepts: Three Simple Examples

The theory of the marginal cost of electricity presented in Schweppe et al, Kluwer 1988, and its implications on transmission pricing presented in Caramanis and Tabors 1994, are summarized.

The marginal cost of delivering an additional unit of electric energy at a specific location and time is the key to transmission pricing. A complete list of costs that must be included in estimating these marginal costs is discussed in Caramanis and Tabors[43], (1994). Once estimated, the difference of marginal costs at two locations reflects the time, location, and direction sensitive marginal cost of a wheeling transaction between these locations (marginal cost at the consuming node minus the marginal cost at the supplying node).

The concepts of at least two sources of cost (transmission line losses and transmission line congestion) and the associated resource rents are presented through three illustrative examples. Readers are referred to the references above for a complete discussion of the issues.

The following points are demonstrated in the examples that follow:

•The Short Run Marginal Cost of delivering energy at bus b during hour t, $SRMC_{b,t}$ can be estimated from system conditions -- nodal generation supply cost, demand pattern, transmission line flows -- at time t, so that it reflects energy, losses, abatement of congestion and other capacity shortages, and other ancillary service costs at time t.

•The Short Run Marginal Cost of Transmission From bus b1 to bus b2 during hour t, is $SRMC_{b1\rightarrow b2,t} = SRMC_{b2,t} - SRMC_{b1,t}$

•Net revenue of transmission from marginal cost pricing can be estimated for time t and its sum forecasted for a yearly period

•Adjustments to marginal cost based transmission prices can be estimated so that the adjusted prices meet revenue reconciliation objectives of a regulated transmission system.

Example 1. No Loop Flow: Losses Only, No Active Constraints

Figure B.1 depicts a three-bus-two-transmission-line system with marginal line loss rate twice the average loss rate. Generation supply curves are shown, and the transfer limit of line CB is assumed to be 1,117 MW at its midpoint. Line flows at each end of each line (denoted by Z), flow directions, and generation and demand levels are also shown. The generator at bus C is not marginal since all of the inexpensive capacity is already dispatched.

The marginal cost at each bus is the cost of the marginal generator located at bus A adjusted for

[43]Caramanis, M., and Tabors, R., D., "Transmission Pricing: Can it be done in Real Time?", Proceedings: 1994 Innovative Electricity Pricing Conference, Tampa Florida, EPRI

marginal line losses. Notice that additional generation at bus A to meet demand at busses B or C, reduces line flows. Hence, to deliver 1 kWH at bus B, generation at bus A must increase only by 1-0.096=0.904 kWH, and the marginal cost at bus B is lower than the marginal cost at A. Similarly, to deliver 1 kWH at bus C, generation at bus A must increase only by 1-0.096-0.11=0.794 kWH.

Assuming that generators are paid the marginal cost at their bus, demand is charged at the same cost, and transmission lines buy electricity at one end and sell it at the other, one observes that transmission lines, as well as generation at bus C will realize a net revenue. Indeed,

Generation Net Revenue =
Gross Revenues - Total Fuel Cost = 18000x28.16 - (1000x10 + 800x20) = $24,688

Transmission Line AB Net Revenue = 513.63x35 - 539.5x31.64 = $907.27/hr

Transmission Line BC Net Revenue = 1039.5x31.64 - 1100x28.16 = $1,913.78/hr

Marginal Cost of Transmission associated with a transaction that supplies one MWH at bus C and consumes one MWH at bus B = 31.64 - 28.16 = $3.48/MWH

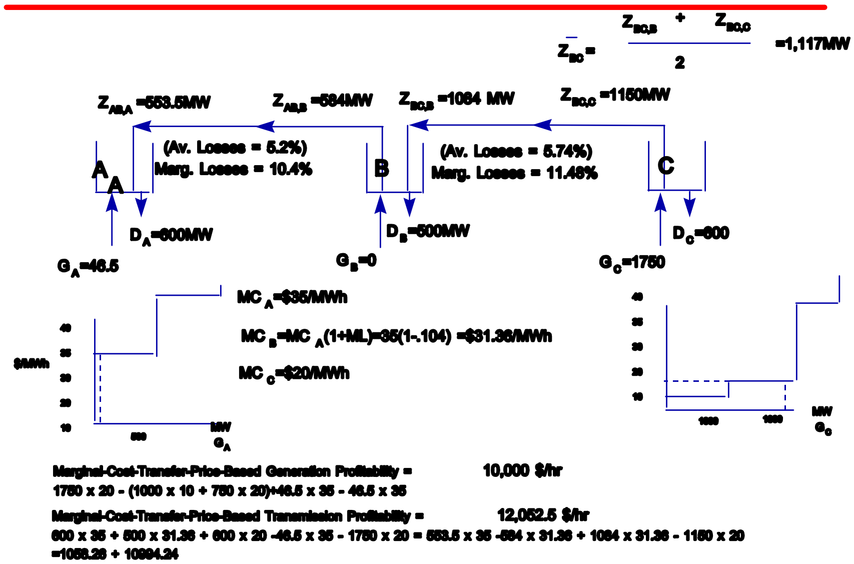
Marginal Cost of Transmission associated with a transaction that supplies one MWH at bus B and consumes one MWH at bus A = 35 - 31.64 = $3.36/MWH

Similarly, transmission costs from bus C to bus A are 35 - 28.16 = $6.84/MWH

Example 2. No Loop Flow: Losses And Active Constraints, Congestion Rent to Constrained Line Only

In this example described in figure B.2, line BC is against its transfer limit of 1,117MW at its midpoint. To sustain this limit, generation at bus C backs down, and now becomes the marginal generator for bus C.

Example 2



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Again, the marginal cost at each bus is the cost of the marginal generator adjusted for marginal line losses. However, whereas for busses A and B the marginal generator is G_A, for bus C, which lies on the other side of the constraint, the marginal generator is G_C that is no longer operating at full capacity.

Notice again that additional generation at bus A to meet demand at bus B reduces line flows. That is, to deliver 1 kWH at bus B, generation at bus A must increase only by 1-0.104=0.896 kWH. Hence, the marginal cost at bus B is lower than the marginal cost at A.

Finally, notice that since the constraining resource is now transmission, the net revenue of the congested line BC is much higher that in the previous example.

Doing the arithmetic one obtains:

Generation Net Revenue =
Gross Revenues - Total Fuel Cost = 1750x20 - (1000x10 + 750x20) = $10,000/hr

Transmission Line AB Net Revenue = 553.5x35 - 584x31.36 = $1058.26/hr

Transmission Line BC Net Revenue = 1084x31.36 - 1150x20 = $10,994.24

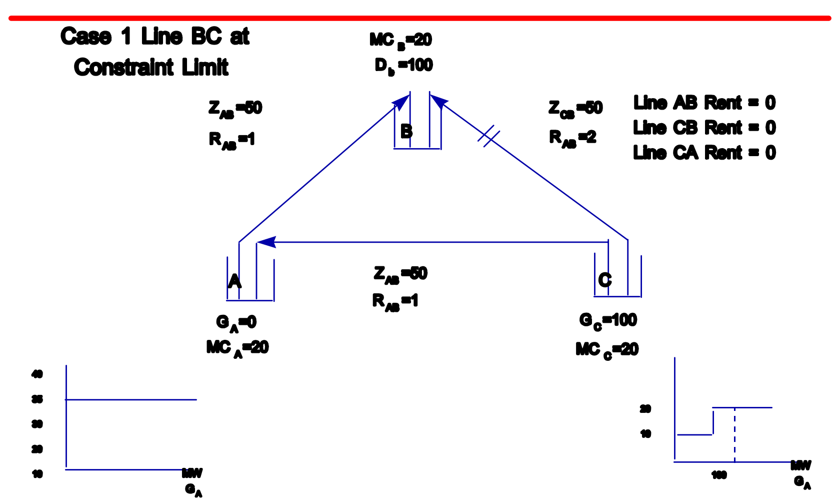
Marginal Cost of Transmission associated with a transaction that supplies one MWH at bus C and consumes one MWH at bus B = 31.36 - 20 = \$11.36/MWH

Marginal Cost of Transmission associated with a transaction that supplies one MWH at bus B and consumes one MWH at bus a = 35 - 31.36 = \$4.64/MWH

Example 3. Loop Flow: Losses ignored for Simplicity, Congestion Rent to Unconstrained Lines As Well

A more realistic example described in figures B.3a and B.3b is discussed here. There is more that one path leading from one bus to the other. To simplify the discussion, we assume that the line losses are negligible, so that we can concentrate on the effect of congestion in the presence of parallel paths or loop flow.

Example 3a



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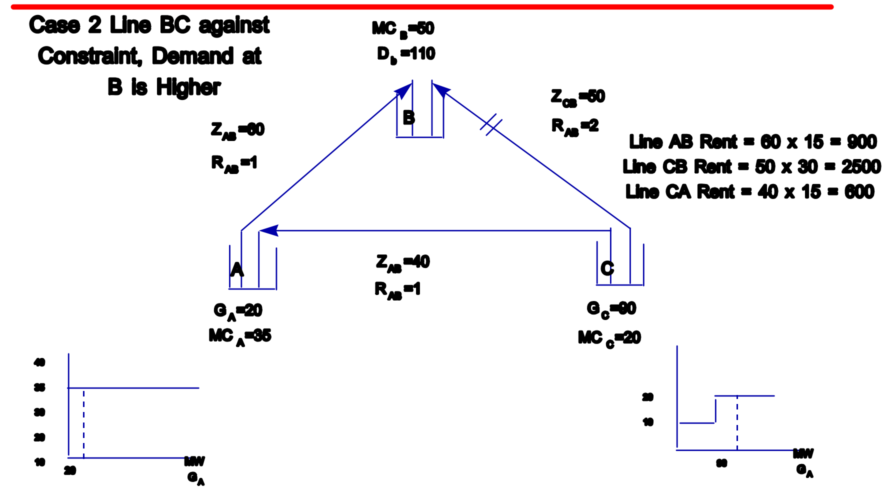
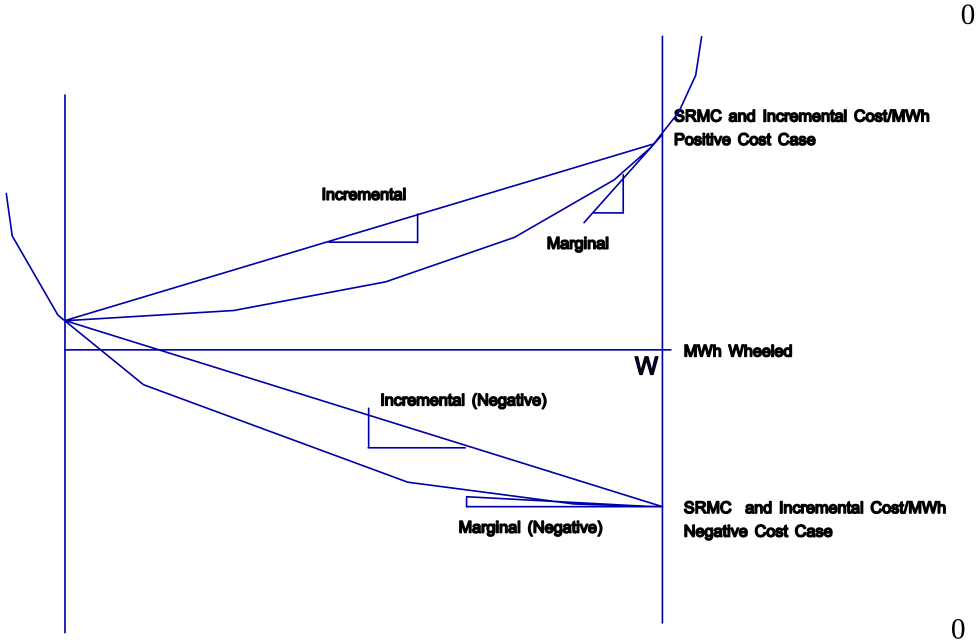
Example 3b



Case 2 Line BC against Constraint, Demand at B is Higher
MC B=50
D b=110
B
Z CB=50
R AB=2
Z AB=60
R AB=1
Line AB Rent = 60 x 15 = 900
Line CB Rent = 50 x 30 = 2500
Line CA Rent = 40 x 15 = 600
A
Z AB=40
R AB=1
C
G A=20
MC A=35
G C=90
MC C=20
MW
G A
MW
G A



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SRMC and Incremental Cost/MWh
Positive Cost Case
Incremental
Marginal
MWh Wheeled
W
Incremental (Negative)
SRMC and Incremental Cost/MWh
Negative Cost Case
Marginal (Negative)
0

We assume that power flows along alternative paths according to the ratio of the resistance of each path. Hence since lines CA and AB pose a resistance of 1 unit each while line CB poses a resistance of 2 units, paths CAB and CB pose equal resistance and the 100 MW generation at bus C travels in equal magnitudes over the two alternative paths to B.

In 3a line BC is just against its transfer limit of 50MW, but no action is needed to avoid flows from exceeding it. Since there are no constraints binding, there is only one marginal generator at bus A. Since in addition there are no line losses, the marginal cost of consumption at each of the three busses is the same, and transmission lines have zero net revenue.

In 3b, however, demand at bus B increases by 10 MW. Since line CB can not transfer more than 50 MW, the additional demand can not be met from generation at C. Generation at A must therefore come into the picture. However, since there are two paths from A to B, namely AB and ACB, and the resistance of these paths is 1 and 3 respectively, 25% of generation at A will travel through ACB and 75% through AB. Thus, the transfer limits of line CB are sustained at 50 MW and the demand at B of 110 MW is met when:

-Power generation at C with a cost of $20/MWH decreases to 90 MW, with 45 flowing towards A and 45 towards B.

-Power generation at A with a cost of $35/MWH increases to 20 MW with 15 flowing towards B and 5 towards C.

-Flow over CA is 45-5 = 40 MW.

-Flow over AB is 45 + 15 = 60 MW.

-Flow over CB is 45 + 5 = 50 MW.

-The Marginal cost of Power at busses A and C is $35/MWH and $20/MWH respectively, namely the cost of the marginal generators at each of these busses.

-The Marginal cost at bus B is the total change in cost from the increase in generation by 20 MW at A and the decrease of generation at C by 10 divided by the 10 MW of additional demand, namely (20x35-10x20)/10 = $50/MWH.

Under these conditions, we observe that the cost of transmission from C to B and from A to B, can be estimated regardless of the fact that there are two possible paths in each case as

$SRMC_{C \to B}$ = 50 - 20 = \$30/MWH
$SRMC_{A \to B}$ = 50 - 35 = \$15/MWH

and all three lines are entitled to congestion rent as they are related to the congested line electrically, namely:

Line AB Congestion Rent = 60 x 50 - 60 x 20 = 60 x 15 = \$900/hour

and similarly

Line CB Congestion Rent = 50 x 30 = \$1500/hour

Line CA Congestion Rent = 40 x 15 = \$600/hour

B.2 Marginal Cost Based Transmission Pricing

The general methodology motivated by the examples above is presented first. We then elaborate on a number of implementations proposed or practiced and show how they are related to space and time dependent short rum marginal cost and the revenue requirements of a regulated transmission system

B.2.1 Marginal Cost Based Pricing

Definition of Terms

-Average cost refers to all energy and transmission services offered during the relevant time unit (hour, month, or year). It is therefore not possible to talk about the average cost of a wheeling transaction, although it is possible to talk about the average variable cost of electricity during a given hour. Sometimes, the term average cost of a wheeling transaction is used ambiguously to mean either the "average incremental cost" of a wheeling transaction, i.e. the incremental cost of the whole transaction divided by the magnitude of the transaction, or the "time averaged incremental cost" of the wheeling transaction over a relatively long period of time.

-Incremental cost refers to the difference in total cost during the relevant time unit (hour, month, or year) with and without a particular transaction, and can be expressed per unit of the transaction.

-Marginal cost refers to the last (marginal) unit of a transaction during the time interval of interest (hour, month, year). If the transaction is the delivery of electric energy to a particular bus b at a specific hour t, the associated short run marginal cost, $SRMC_{b,t}$, is the variable cost, incurred by the power system in order to supply the last MWh of energy at bus b during hour t. The short run marginal cost of a wheeling transaction from bus b_1 to bus b_2 during hour t, is the difference of the short run marginal cost at the two busses. We therefore have the following definitions:

$SRMC_{b,t}$	: The Short run MC per MWh of energy delivered at bus b at time t
$SRMC_{b2,t}$-$SRMC_{b1,t}$	: The Short Run MC per MWh of energy wheeled from bus b_1 to bus b_2.

-Short Run refers to costs over a relatively short period of time.

-Long Run refers to costs over a long period of time such as a year.

Note: Depending on the costs considered (Variable versus Fixed), the duration of the time period (Short versus Long), and the type of the transaction (Non-firm versus Firm), the cost accounting unit may be energy (MWh) or power (MW). Since SRMC is the basic building block, it is generally preferable to use an energy (MWh) based unit.

Short Run Cost Properties

-Both the incremental and marginal variable cost of a wheeling transaction vary with time (i.e. power system condition) and location of the wheeling parties. They can both be positive or negative, i.e. a wheeling transaction may increase or decrease variable costs depending on its direction (with the flow or counter flow)

-Whenever positive, the short run marginal costs of a wheeling transaction are always larger than the corresponding incremental costs. Conversely, whenever negative, the marginal benefits (i.e. the negative of the negative costs) are smaller than the incremental benefits (see figure B.4). Provided that no additional transmission investment was undertaken to accommodate the wheeling transaction and included in the native customer rate base, an important consequence of this fact is that a short run marginal cost based wheeling rate will always result in:

•sufficient revenue to cover the incremental cost of the transaction and hence keep the native customers harmless, and

•additional revenue which can be distributed to the stockholders and or benefit the native customers.

Figure B.4: $W \times SRMC > W \times SRIC$

$W =$ MWh wheeled, SRMC, SRIC Short Run Marginal and Incremental cost respectively

-SRMC based rates convey information that motivates wheeling parties to make efficient operating decisions, namely:

•wheel more during times of low SRMC, less during times of high SRMC

•wheel only when the value to them of the marginal (last) MWh wheeled is higher than the cost of actually wheeling that MWh.

-SRMC based rates provide the only self consistent and non-arbitrary means for unbundling gross and net revenues by generation and transmission capital stock component (see table B.1 below). In fact, the net revenues provide a means of ranking the profitability of groups of or of individual capital stock components.

Table B.1

Unbundling of Revenues and Profitability Relationships

Capital	**Gross Revenue, hour t**	**Net Revenue, hour t**
All Generation	$\Sigma_{b,i}\ G_{b,i,t}SRMS_{b,t}$	$\Sigma_{b,i}\ G_{b,i,t}[SRMS_{b,t}-AGC_{b,i,t}]$
Generator i	$G_{b,i,t}SRMS_{b,t}$	$G_{b,i,t}[SRMS_{b,t}-AGC_{b,i,t}]$
All Transmission	$\Sigma_b\ D_{b,t}SRMS_{b,t}$	$\Sigma_b\ [D_{b,t} - \Sigma_i\ G_{b,i,t}]SRMS_{b,t}$
Transmission Line j connecting busses b_1 and b_2	$SRMS_{b1,t}\ Z_{b1\to b2,t}$	$-[SRMS_{b1,t}\ Z_{b1\to b2,t} + SRMS_{b2,t}\ Z_{b2\to b1,t}]$

where:

$SRMC_{b,t}$:SRMC of delivering a MWh of energy at bus b during hour t

$G_{b,i,t}$:Hour t generation level of generator i located at bus b

$AGC_{b,i,t}$:Hour t average generation cost of generator i located at bus b

$Z_{b1\to b2,t}$:Power flow over transmission line connecting busses b_1 and b_2 at the b_1 bus end of the line, and similarly for $Z_{b2\to b1,t}$. Note that $Z_{b1\to b2,t}$ or $Z_{b2\to b1,t}$ is negative depending on whether the flow is into the line (positive) or out of the line (negative).

$D_{b,t}$:Hour t energy demanded at bus b

-Given the fact that $SRMC_{b,t} \geq AGC_{b,i,t}$ for all b, i, and t, we can conclude that *SRMC based net revenue of generation is positive*.

-Power flows from low SRMC nodes to high SRMC nodes[44]. Therefore, $[D_{b,t} - \Sigma_i G_{b,i,t}]$ terms are positive at high SRMC nodes (i.e. primarily demand nodes) and negative at low SRMC nodes (generation nodes). Hence *SRMC based net revenue of transmission is positive*.

[44]See Schweppe, Caramanis, Bohn, and Tabors, *Spot Pricing of Electricity*, Kluwer Academic Publishers, Boston, 1988.

Long Run Cost Properties and Relationship to SRMC

-Long Run Average Variable Cost of electricity is simply the time average of the short run average cost.

-The Long Run Incremental or Marginal Cost of a firm load or wheeling transaction (i.e. a load or wheeling transaction which takes place on each and everyone of the 8760 hours of a year, year after year) is the time average of the corresponding Short Run Incremental or Marginal Cost.

-As shown above, "Pure" SRMC based rates result in net revenues during each hour that they are applied. Therefore, since LRMC is the time average of SRMC, pure marginal cost based rates (whether short or long term) will result in revenue that exceeds variable costs. This excess will allow recovery of a certain proportion of the fixed costs. In fact, the high net revenues that will be realized during times of high SRMC will result from difficult to sustain capacity constraints and in rare occasions load shedding, which represent the opportunity cost of additional capital equipment during these times. Depending on the power system at hand, the extent to which fixed costs are recovered through "Pure" Variable Marginal Cost pricing (including the opportunity cost of capacity shortage) may vary. In recent empirical studies of rather strong transmission systems such as that of Great Britain, the capital cost recovery proportion has been found to be above 50%.

SRMC Based Rate Design Methodology

The proposed transmission rate design methodology is based on the following major conclusions derived in the discussion of section II:

•The Short Run Marginal Cost per MWh of a wheeling Transaction of W_t MWh from bus b_1 to bus b_2 at time t is the difference of the SRMC at these busses[45],

$$SRMC_{b1\rightarrow b2,t} = SRMC_{b2,t} - SRMC_{b1,t}$$

where $SRMC_{b1\rightarrow b2,t}$ represents an allocation of all costs that are assignable to the wheeling transaction.

• The annual revenue

$$\Sigma_t \, [W_t \times SRMC_{b1\rightarrow b2,t}]$$

is larger than the average variable costs of the wheeling transaction. In fact, it even exceeds the transaction's incremental costs. The excess of revenues over the average variable costs can be allocated to the coverage of fixed costs.

•Since no specific equipment can be identified as serving exclusively the needs of the wheeling transaction, the fixed costs of the wheeling transaction are undefined. The marginal cost

[45]The fact that a wheeling transaction may involve more than one marginal bus at the selling and buying utility can be easily accounted for by considering a weighted average of all busses involved.

based revenue of the wheeling transaction has taken care of all variable costs and a portion of the fixed costs. This leaves a residual in overall revenue requirements that can not be allocated to specific services. The only way to allocate this residual is through a uniform distribution rule that does not depend on time or location of the use. Time and location effects have been captured to the extent that they impact the use specific marginal costs.

An example of a rate design which is consistent with the above conclusions is outlined below:

-Step 1 Calculate annual gross generation and transmission revenues by summing hourly revenues as described in Table 1. In this calculation treat selling busses of wheeling transactions as generation busses and buying busses as demand busses[46].

-Step 2 Compare gross revenues to annual variable and fixed costs, and estimate the residual difference. Although in theory the residual might be negative, under reasonable circumstances it will be positive[47].

-Step 3 Distribute the residual to all users. One reasonable way to do so is to distribute it to all demand (or demand equivalent) busses on a per MWh/year basis[48].

Assuming that the example of step 3 is adopted, the wheeling rate at hour t will be:

$$SRMC_{b1\rightarrow b2,t} + \mathbf{c} = SRMC_{b2,t} - SRMC_{b1,t} + \mathbf{c}$$

where **c** is a time and location invariant constant corresponding to the residual between SRMC revenues and total required revenues divided by the annual MWh of demand.

B.3 Transmission Rate Alternatives

A number of alternative transmission rates have been proposed and practiced. These are discussed briefly and then compared.

•Congestion Pricing

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[46]This is equivalent to treating all users, native as well as wheeling parties, on a similar basis. Each user (or class of users) incurs its portion of assignable costs to the extent that it is responsible for it on the margin.

[47]Residuals will be generally different from zero for reasons that are either transient or systematic. Specifically:

•*Transient Reasons* are related to the fact that certain investments selected ignoring an open access future may become suboptimal and be stranded in an open access future (this will show in terms of low net revenues as calculated in table 1,

•*Systematic reasons* are related to

-Economies of scale in transmission technology

-Lumpiness of transmission investments

[48]Variations based on lump sums, connection charges on a per MW basis, or other ways to collect the residual charges may certainly be adopted without major changes to the procedure described.

Nodal transmission prices through long term contracts that reflect the expected average congestion costs over the life of the contract have been proposed by Hogan[49]. The characteristics of this rate are:

-Transmission rights between two locations (nodes or busses) can be secured through a long term contract.

-The cost of the long term contract is reflective of the expected congestion costs over the life of the contract associated with supplying power at one location and consuming it at the other. These costs do not refer specifically to certain transmission lines. They capture the transmission costs involving all parallel paths and electrically connected transmission facilities as well as the marginal cost of energy as elaborated in B.1, and B.2.

-Non-congestion related costs, such as the cost of line losses, are charged separately and may vary with time.

One of the properties of this arrangement is that it maintains the spatial differentiation of transmission costs and conveys efficient signals for long term locational decisions. It also reflects short term cost of losses which are present on a regular basis and motivates efficient operational decisions in the absence of congestion conditions. The opportunity cost of the transmission rights during infrequent congestion incidents may augment the incentives for efficient operational decisions during capacity shortfall times as well. Cost predictability by the right holder is the main advantage of long term contracts for transmission congestion pricing.

•Nodal Real Time Pricing Implementation Requirements

Ilic et al[50] have outlined a method which allows for actual implementation of Real Time Transmission pricing. This proposal is complementary to the long term contracts discussed above since it may be applied to non-right holders and provide right holders with the correct opportunity cost for efficient operational decisions. It is based on:

-A revenue reconciled real time transmission cost based on the location and time specific short run marginal cost.

-An independent System Operator (ISO) determines the real time rates while dispatching the generation, transmission, and reserve facilities on the basis of supply cost curves that the ISO compiles from bids made by generators for energy, operating reserve, load following, frequency and VAR support, and other ancillary services.

-An iterative process during which transmission requirements (supply and consumption at specific nodes) react to prospective tentative prices determined by the ISO on the basis of Optimal Power Flow calculations, and the ISO adjusts the dispatch of resources as

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[49]Hogan, W., W., "Contract Networks for Electric Power Transmission: Technical Reference" Energy and Environmental Policy Center, JFK School of Government, Harvard University, 1991, and Journal of Regulatory Economics, Vol. 4 pp. 211-242, 1992.

[50]Ilic, M. D., Graves, F., Fink, L.H., DiCaprio, A., "A Framework for Operations in Competitive Open Access Environment" MIT Technical Report LEES TR95-009, October 1995, also published in *The Electricity Journal* April, 1996, V9 no 3, pp. 61-69.

needed, leads to an equilibrium supply consumption pattern and the associated real time transmission rates.

•Zonal Pricing

Empirical studies have shown that nodal variability of marginal costs is very small within appropriately selected geographical aggregations of nodes, called zones (Walton and Tabors 1996)[51]. Time averaging of the Zonal rates can yield efficient transmission rates that are significantly easier to administer.

•Contract Path

The contract path method has been used in practice to price transmission between two locations. The form of this rate, is similar to the zonal pricing method provided that the cost of using the contract path is based on the marginal cost of transmission. Traditional calibrations of contract path rates have been based on the capital depreciation costs of an imaginary path that may not include many parallel paths that play an important role in the true marginal cost of a transaction.

•MW Mile

The MWMile method provides the basis of actual transmission rates in practice today. It is based on the capital depreciation cost of all parallel paths between two locations on the transmission network. These depreciation costs are weighted by the proportion of power that would go through each path if the transmission system was loaded only with the transaction of interest. Although a positive step relative to the postage stamp method, the MWMile approach does not address the cost of losses and congestion explicitly.

•Incremental Cost

This method is based on a case by case evaluation of incremental costs associated with a specific transmission transaction. Since there are typically many transmission transactions, the order with which each transaction is added to the rest of the generation and consumption is important to the estimation of the transactions incremental costs. In contrast to the marginal cost approach which evaluates each transmission transaction on the margin (i.e. all transactions are evaluated in the presence of all other transactions), the incremental approach is extremely cumbersome and any particular order that may be considered is arbitrary from the point of view of economic efficiency.

•Postage Stamp

The postage stamp method involves a flat transmission charge regardless of the location, distance or timing of transmission. It is administratively simple but does not capture spatial or temporal variability.

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[51]Walton Steven., Tabors, Richard D., "Zonal Transmission Pricing: A Methodology and Preliminary Results from the WSCC" EPRI Innovative Pricing Conference Proceedings, LaJolla, California, March 1996.

B.4 Comparison of Transmission Pricing Alternatives

Marginal Cost Based Transmission Pricing discussed above can provide the starting point to the various pricing alternatives discussed above. In fact, it has the following characteristics which provide a framework for comparing alternative rates and for choosing amongst alternative rates by matching a rate's capabilities to resolve among the various transmission costs and the desired resolution dictated by the specific cost structure of a given transmission system:

•It conveys SRMC and LRMC signals to users motivating
-efficient operational/dispatch decisions (wheel more when the SRMC is low, less when it is high)
-efficient long term decisions (potential buyers and sellers pursue wheeling agreements wherever annual or time averaged wheeling costs are expected to be low)

•Whenever the residual dominates, i.e. **c** is larger that $SRMC_{b1\rightarrow b2,t}$, an economically efficient transmission rate can be designed and implemented in the form of a postage stamp rate.

•Whenever the residual term is relatively small, and the $SRMC_{bi\rightarrow b2,t}$ term does not vary with time but is sensitive to the distance of b_1 and b_2 busses, an economically efficient transmission rate can be designed and implemented in the form of a contract path.

•Whenever the residual term is relatively small, and the $SRMC_{bi\rightarrow b2,t}$ term does not vary with time but is sensitive to the location of b_1 and b_2 busses rather than simply their distance, an economically efficient transmission rate can be designed and implemented in the form of a Parallel Path, MWMile rate.

•Whenever the $SRMC_{bi\rightarrow b2,t}$ term dominates, varies significantly with time and is sensitive to the location of b_1 and b_2 busses, the SRMC signals will be significant in promoting efficient transmission decisions.

•Since time variability is almost universally encountered, the design of rates for wheeling transactions with different degrees of firmness, ranging from a high load factor firm transaction to seasonal or temporary short term wheeling transactions, will be most efficient if it is based on the SRMC. Parallel Path, MWMile or other time invariant cost based designs are not appropriate for pricing non-firm wheeling.

•Allocation of the residual revenue requirements on a per MWh basis will result naturally in a higher allocation to frequent users associated with firm transactions.

•The transmission grid owner will not be allowed to realize monopoly profits since the residual term will be calculated to satisfy revenue requirements. At the same time, the transmission grid owner will have no incentive to refrain from investing in transmission since a mechanism for realizing the required revenues will be in place.

•Recall that SRMC-based revenues are guaranteed to exceed not only average variable costs but also incremental variable costs. Native customers will be therefore held harmless in the absence of additional transmission investments undertaken to support wheeling transactions. In the presence of significant transmission investments to support sizable new wheeling activity, native customers will be likely to benefit from economies of scale that will accompany the new investments (for example higher kVA lines).

•Long Term Transmission contracts can be based on forecasts of future $SRMC_{b,t}$ time trajectories, or forecasts of the statistics of these trajectories. Transmission owners (or perhaps independent energy futures brokers) can provide wheelers with a hedge[52] which, for example, provides for a higher fixed component and a lower or capped time varying component in the rate. Nodal congestion pricing, discussed above, assigns the time averaged congestion costs to a long term transmission right contract and leaves the easily measurable periodic cost of losses to a time varying charge. Such an arrangement would not be different in form from current rates that consist of a fixed per MWh rate and a time varying fuel adjustment rate. In the limit, constant rates may be obtained by reducing the time variability of the rate to zero.

•The cost (or revenue requirement) allocation to native customer classes may also be done using the same methodology (i.e. assignable costs according to the extent responsible and non-assignable costs on an equal basis, namely using the same time invariant formula for all users). This approach would result in a self consistent rate structure and the relative importance of the non-assignable portion of costs will likely decrease with time. Of course, the initial impact of transition costs that will result from the creation of losers and winners as total costs are redistributed among customer classes, will have to be addressed. The magnitude of these costs in an empirically quantifiable issue.

Given the discussion above, alternative transmission pricing methods are compared in tables B.2 and B.3 below.

[52]A risk premium may be factored in the long term contract's fixed rate component.

TABLE B.2
Comparison of Transmission Pricing Methods: Implementation Considerations

Pricing Method	Provision for Stable Prices	Administrative Simplicity 1-5	Notes
Postage Stamp	Yes	1	Simple, but not reflective of reality in either space or time
Contract Path	Yes	1	Simple but not reflective of system power flows
MWMile/Parallel Path	Yes as expected Value	3	Load flow based, agreed upon rules required for consistent implementation
Incremental Cost	Yes	5	Requires extensive assumptions about future developments and continuous bookkeeping of individual project costs. Administratively burdensome and inconsistent over time, particularly w.r.t. order of transaction evaluation.
Congestion based Nodal Long Term Contracts	Yes	4	Requires extensive assumptions about future costs and demands. Consistent with Real Time Transmission Rates. Administratively burdensome without Zonal aggregation
Zonal Pricing (The UK Model)	Yes	2	Load flow based, administratively relatively simple, provides stable and forecastable prices on annual basis
Nodal Real Time Pricing	Yes Through Futures Contracts	4	Provides basis for range of price structures differentiated in both time and space. Requires OPF model and Iterative process coordinated by Independent System Operator

TABLE B.3
Comparison of Transmission Pricing Methods: Cost Resolution Capabilities

Pricing Method	Account for Constraints/ Congestion	Reflect Prudent Costs for Services	Reflect actual Power Flows	Reflect distance and location costs	Reflect direction of flow
Postage Stamp	No	No	No	No	No
Contract Path	No	No	No	Distance	No
MWMile/Parallel Path	It may	Yes, as defined	It may	Electrical Distance	Yes
Incremental Cost	Yes, for Investment	Generally yes, time averaged	Long term only	Generally yes	Long term only
Congestion based Nodal Long Term Contracts	Yes	Generally yes, time averaged congestion	Yes	Generally yes	Yes
Zonal Pricing (The UK Model)	Yes	Yes, time averaged congestion and losses	Time averaged	Yes	Yes
Nodal Real Time Pricing	Yes	Yes, time specific, Residual Term for capital cost recovery reconciliation	Yes	Yes	Yes

Finally, Table B.4 below provides guidelines for matching a particular transmission system's transmission cost resolution requirements to the simplest transmission rate that is capable of providing the requisite resolution. For the conditions prevailing in New England, a Zonal Pricing approach appears adequate.

Table B.4
Comparison of Pricing Methods: Matching Cost Resolution Requirements and Capabilities

Time Variability Spatial Variability	Little	Significant
Low	Postage Stamp	Spatially Aggregated Real Time Price
Medium (Distance)	MWMile/Contract Path	Zonal Real Time Price
High	Zonal (U.K Model)/ Congestion Long Term Contracts	Nodal Real Time Price